STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ., 8-1-8.5-1 ET SEQ. AND 8-1-8.8 ET SEQ.	)	**CAUSE NO. 45052**

JOINT INTERVENORS' SUBMISSION OF PROPOSED ORDERS

The attached Proposed Orders are filed on behalf of the following parties to this proceeding: Alliance Coal, LLC, Sunrise Coal, LLC, the Indiana Coal Council, Inc., Citizens Action Coalition of Indiana, Sierra Club Hoosier Chapter, Valley Watch, Inc., and the Indiana Office of the Utility Consumer Counselor ("OUCC") (together, "Joint Intervenors"). Joint Intervenors request the Commission deny Southern Indiana Gas & Electric Company's request in conformance with Joint Intervenors' Motion for Partial Summary Judgment (the "Motion") and the analysis set forth in the Attachment A (the "Proposed Order"). In the alternative, should the Commission elect to deny the Motion, Joint Intervenors submit Attachment B (the "Alternative Proposed Order"), setting forth their proposed analysis and conclusions on the merits. Joint Intervenors contend that under Indiana's distinctive summary judgment standard that summary judgment was proper in their favor. For similar reasons, judgment on the merits at trial was also then appropriate. To be clear, Joint Intervenors do not waive their arguments on the Motion by filing the Alternative Proposed Order on the merits.

Respectfully submitted,

Nikki Shoultz

Nikki G. Shoultz, #16509-41
Jeffery Earl, #27821-64
Kristina K. Wheeler, #20957-49A
BOSE MCKINNEY & EVANS LLP
111 Monument Circle, Suite 2700
Indianapolis, IN 46204
(317)684-5242
(317)684-5173 (facsimile)
nshoultz@boselaw.com
kwheeler@boselaw.com
jearl@boselaw.com
ATTORNEYS FOR ALLIANCE COAL, LLC
AND INDIANA COAL COUNCIL

William Fine
Randall C. Helmen
Lorraine Hitz-Bradley
Office of Utility Consumer Counselor
PNC Center
115 West Washington Street, Suite 1500S
Indianapolis, IN 46204
wfine@oucc.in.gov
rhelmen@oucc.in.gov
lhitzbradley@oucc.in.gov
infomgt@oucc.in.gov
ATTORNEYS FOR THE INDIANA
OFFICE OF THE UTILITY CONSUMER
COUNSELOR

Jennifer Washburn
Margo Tucker
Citizens Action Coalition of Indiana, Inc.
1915 W. 18th Street, Suite C
Indianapolis, IN 46202
jwashburn@citact.org
mtucker@citact.org
ATTORNEYS FOR CITIZENS ACTION COALITION OF INDIANA, VALLEY WATCH AND SIERRA CLUB

Robert Hartley
Alan S. Brown
Darren Craig
Frost Brown Todd LLC
201 North Illinois Street, Suite 1900
P.O. Box 44961
Indianapolis, IN 46224-0961
rhartley@fbtlaw.com
abrown@fbtlaw.com
dcraig@fbtlaw.com
ATTORNEYS FOR SUNRISE COAL, LLC

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
mkurtz@BKLlawfirm.com
ATTORNEYS FOR INDIANA COAL COUNCIL

Thomas Cmar, Atty. No. 3491-95-TA
Earthjustice
1010 Lake Street, Suite 200
Oak Park, IL 60301
tcmar@earthjustice.org

Cassandra McCrae, Atty. No. 6607-95-TA
Earthjustice
1617 John F. Kennedy Blvd., Suite 1130
Philadelphia, PA 19103
cmccrae@earthjustice.org

Raghu Murthy, Atty. No. 6633-95-TA
Earthjustice
48 Wall Street, 15th Floor
New York, NY 10005
rmurthy@earthjustice.org

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served upon the following counsel electronically or via regular mail this 22ND day of January, 2019:

P. Jason Stephenson
Robert E. Heidorn
Goldie T. Bockstruck
Vectren Corporation
One Vectren Square
211 N.W. Riverside Drive
Evansville, IN 47708
jstephenson@vectren.com
rheidorn@vectren.com
gbockstruck@vectren.com

Nicholas K. Kile
Hillary J. Close
Lauren M. Box
Barnes & Thornburg LLP
11 S. Meridian Street
Indianapolis, IN 46204
Nicholas.kile@btlaw.com
Hillary.close@btlaw.com
Lauren.Box@btlaw.com

Todd A. Richardson
Tabitha L. Balzer
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282-0003
trichardson@lewis-kappes.com
tbalzer@lewis-kappes.com

Nikki Shoultz

Nikki G. Shoultz, #16509-41

3571488_1

Attachment A

JOINT INTERVENORS' ATTACHMENT A

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ, 8-1-8.5-1 ET SEQ., AND 8-1-8.8 -1 ET SEQ.	)	CAUSE NO. 45052

ORDER OF THE COMMISSION

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

Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity ("CPCN") for a new duct-fired F-class 2x1 combined cycle combustion turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. We convened a prehearing conference on April 3, 2018, and issued a prehearing conference order on April 11, 2018. Petitions to intervene were filed by (1) the Vectren Industrial Group; (2) Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); (3) the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); (4) SABIC Innovative Plastics Mt. Vernon, LLC, St. Joseph Energy Center, LLP, St. Joseph Phase II LLC, and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony.

On July 19, 2018 Joint Intervenors, the Coal Parties, Vectren Industrial Group, and the OUCC ("Movants") filed a joint Motion for Partial Summary ("Motion") Judgment asking the Commission to determine as a matter of law that Vectren South's petition for a CPCN to construct a CCGT must be denied because no statewide energy analysis existed that satisfied the statutory criteria of Ind. Code § 8-1-8.5-3(a). On July 27, 2018, Vectren South filed its Preliminary Response and Partial Designation of Evidence in opposition to that Motion. On August 3, 2018, the Movants filed their Preliminary Reply to Vectren South's response and requested an expedited ruling holding the procedural schedule in abeyance. By Docket Entry of August 6, 2018, that request was denied, and the date for Vectren South's formal response and evidentiary designation was set for August 20, 2018. On August 20, 2018, Vectren South filed its response and designation of evidence. On September 12, 2018, the Movants filed their Reply in support of the Motion and reply designation of evidence.

An evidentiary hearing commenced on October 9, 2018. Before the first witness was called, Alliance Coal asked the Commission to rule on the Motion prior to calling Vectren South's first witness, noting that the spirit of Trial Rule 56 is to narrow the issues in advance of trial. Tr. A-5. In the alternative, Alliance Coal requested the Commission continue the evidentiary hearing to allow the Commission to rule on the Motion. *Id.* The Presiding Officers denied Alliance Coal's request, ordered the evidentiary hearing to proceed and stated the Commission would take the Motion under advisement and rule in the Commission's Final Order. *Id.*

After Vectren South admitted its evidence into the record and rested its case, Alliance Coal moved to partially dismiss that portion of Vectren South's case requesting a CPCN for new generation pursuant to Indiana Trial Rule 41(B), 170

Ind. Admin. Code 1-1.1-12(3) and (5) and 170 I.A.C. 1-1.1-26 (the "Dismissal Motion"). The Dismissal Motion was joined by the OUCC, CAC, Sierra Club, Valley Watch, ICC, and Sunrise (collectively, the "Movants").[1]

The Commission, having heard the evidence and being duly advised, now finds as follows:

1. **Notice and Jurisdiction**. Due legal and timely notice of the prehearing conference, public field hearing, and evidentiary hearing in this Cause was given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Petitioner is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Petitioner may seek Commission approval of Certificates of Public Convenience and Necessity pursuant to the chapters. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding in the manner and to the extent provided by laws of the State of Indiana.

2. **Petitioner's Characteristics and System**. Petitioner is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Petitioner provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Petitioner's electric utility business. Petitioner renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages, and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light, and power for residential, commercial, industrial, and municipal uses. Petitioner furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois, and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five (5) coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick 4 (150 MW). Petitioner procures 100% of its coal supply from mines located in Indiana. The other 248 MW of net generating capacity Vectren South owns and operates consist of 3 MW of land-fill gas generation, and 245 MW of natural gas fired peaking units: A.B. Brown 3 (80 MW), A.B. Brown 4 (80 MW), BAGS 2 (65

[1] The Vectren South Industrial Group did not join in the T.R. 41(B) Motion.

MW), Northeast 1 (10 MW), and Northeast 2 (10 MW). In addition, Vectren South has long term purchase power contracts for wind generated energy: Fowler Ridge (50 MW) and Benton County (30 MW).

Vectren South's operations are subject to federal, state, and local rules promulgated by, among others, the U.S. Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Commission Discussion on Motion for Partial Summary Judgment and Trial Rule 41(B) Motion to Dismiss

In support of the Motion for Partial Summary Judgment, the Movants first argued that the statute governing the Commission's consideration of a Certificate of Public Convenience and Necessity to construct a new electric generating facility is clear and unambiguous. They noted the statute requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity" (hereafter "Statewide Analysis"). Ind. Code § 8-1-8.5-3(a). That statute also mandates that when acting on any request by any utility for construction, the "commission shall consider the [Statewide] analysis." Ind. Code § 8-1-8.5-3(c). Second, the Movants argued that since no Statewide Analysis existed, it was impossible for the Commission to comply with its governing statute, and for any party to proffer evidence relevant to whether approval of Vectren South's proposed project was consistent with the Statewide Analysis.

The Movants incorporated the arguments supporting the Motion into their Dismissal Motion during the evidentiary hearing. The Movants noted that the Commission is required by Ind. Code § 8-1-8.5-3(c) to consider the Commission's own Statewide Analysis "in acting upon any petition by any utility for construction" of new generation facilities and that the Commission is unable to satisfy this requirement because the Statewide Analysis was not completed prior to the commencement of the evidentiary hearing. Tr. J-29. The Movants argued that Vectren South, as the Petitioner, bears the burden to prove that its request aligns with the Statewide Analysis and that Vectren South's evidence is devoid of any showing of consistency with the Statewide Analysis.

Ind. T.R. 41(B) states in part, that after the party with the burden of proof has completed its presentation of evidence, the opposing party may move for a dismissal on the grounds that upon the weight of the evidence and the law there has been shown no right to relief. As the Movants noted, this Commission has acknowledged that upon completion of a case-in-chief, a motion to dismiss is appropriate pursuant to Ind. T.R. 41(B). *In re Joint Petition of Flatfork Creek Development,* Cause No.

38883, 1990 Ind. PUC LEXIS 63 (I.U.R.C. Mar. 7, 1990) (the Commission granted the OUCC's oral motion to dismiss pursuant to Trial Rule 41(B), finding that the petitioners had not met their statutory burden to prove they should be issued a Certificate of Territorial Authority and dismissing the proceeding); *In re Pipeline Safety Division's Investigation into LGS Plumbing, Inc.*, Cause No. 44573, Ind. PUC Lexis 397 (I.U.R.C. Dec. 30, 2015); *In re Indiana Bell*, Cause No. 38970, Ind. PUC. LEXIS 473, at *61-62 (I.U.R.C. Dec. 31, 1991); and *In re Complaint to Declare Void Town of Fishers Municipal Ordinance*, Cause No. 38949, 1991 Ind. PUC Lexis 85, at*7-8 (I.U.R.C. Mar. 31, 1991).

From an evidentiary perspective, the Movants raise a legitimate concern. Because no Statewide Analysis existed at the time Vectren South offered its evidence into the record, there is no record evidence upon which we may conclude that Vectren South's request is consistent with the Statewide Analysis as required by Ind. Code § 8-1-8.5-3(c). We find that as a matter of law, the Commission is unable to satisfy the statute's requirement because Vectren's evidence fails to address or establish that Vectren's CPCN request is consistent with the Commission's Statewide Analysis. We therefore conclude it is appropriate to grant the Movants' Dismissal Motion.

The Movants argued that should the Commission decline to dismiss Vectren's CPCN request and if the Commission proceeded to issue its Statewide Analysis on the following day as expected, that the Commission should allow the parties an opportunity to provide evidence on the extent to which Vectren's CPCN request is consistent with the Statewide Analysis. Tr. J-32. The Movants argued that it would be inconsistent with due process to deny Movants the opportunity to present evidence on Vectren's compliance with Ind. Code § 8-1-8.5-3(c).

The Commission issued its Statewide Analysis during the evidentiary hearing on October 16, 2018, seven days after the evidentiary hearing commenced and forty-three days after the Movants were required to pre-file testimony in the proceeding. The Presiding Officers denied the Movants' request for a continuance to allow them an opportunity to present evidence on the extent to which Vectren South's petition is consistent with the final Statewide Analysis. We now consider whether the Movants should have been entitled to present evidence relevant to whether Vectren South's CPCN request is consistent with the Statewide Analysis pursuant to Ind. Code § 8-1-3.5-3(c). Vectren South claims that this is the Commission's sole inquiry. Tr. J-35. We disagree.

The Commission is the final arbiter of whether Vectren South satisfied each element of the applicable statutes, but the Public and intervenors have the right to present evidence relevant to the Commission's inquiry. Indeed, the parties have filed hundreds of pages of pre-filed testimony aimed to provide evidence on dozens of statutory provisions applicable to Vectren South's request. We find that it was inconsistent with notions of due process to deny Movants the opportunity to present evidence on the project's consistency with our Statewide Analysis, especially since our Statewide Analysis was issued in the middle of the evidentiary hearing and the Movants specifically and repeatedly requested an opportunity to present evidence addressing the alignment of Vectren South's proposed CCGT with the Statewide Analysis. Vectren South did not object to the Movants' evidence on Vectren's compliance with other elements of the statute and we find it improper to create a different standard for consideration of whether Ind. Code § 8-1-3.5-3(c) was satisfied. Based on the foregoing, we find that the Presiding Officers erred in closing the evidentiary record and denying the Movants an opportunity to present such evidence.

Ultimately, we must make our findings based on the evidentiary record before us. Because the Statewide Analysis was offered into evidence in the middle of the evidentiary hearing[2], no party offered evidence on whether Vectren South's CCGT proposal is consistent with the Statewide Analysis. This is so because the opportunity to present such evidence expired before the Statewide Analysis was issued and admitted into the record. We conclude that there is not sufficient record evidence to support a finding that Vectren South's request for a CPCN is consistent with our Statewide Analysis as required by Ind. Code § 8-1-3.5-3(c). Accordingly, we deny Vectren South's CPCN request.

4. Evidence

[The evidentiary summary from Joint Intervenors' Alternate Proposed Order are incorporated here by reference]

5. Commission Discussion and Findings

A. CPCN for CCGT and related relief

Consistent with our discussion of the Movants' Motion for Partial Summary Judgment and Dismissal Motion, we deny Vectren South's CPCN request and related relief.

B. CPCN for Culley compliance projects and related relief

We move next to Vectren South's request for approval of the Culley 3 compliance project. Witness Lauren Aguilar of the OUCC recommended that we deny Vectren South a CPCN for the Culley 3 compliance projects pursuant to Ind. Code ch. 8-1-8.4, *et seq*. Under the federal mandate statute (Ind. Code §§ 8-1-8.4-5, -6, and -7), Vectren South has requested several projects for environmental remediation at Culley 3: costs for closure of the inactive Culley West pond in order

[2] Pet. Admin. Not. Ex. 2.

to build a new process and storm water pond on the same location; spray dry evaporator; and a submerged chain conveyor for ash transport. Pub. Ex. 1, p. 26. However, to recover costs under the federal mandate statute, a utility must show that the project is required under specified federal statutes: the Clean Air Act, the Water Pollution Control Act, Resource Conservation and Recovery Act, or the Toxic Substances Control Act. Pub. Ex. 1, pp. 26-27.

Unfortunately for Vectren, its requested Culley West pond closure costs do not meet the federal mandate statute's requirements. Vectren South witness Angila Retherford testified that the closure was necessary to "reuse the space to construct facilities necessary to comply with the ELG rule." Pet. Ex. 9, p. 18, ll. 19-20. In addition, closure of the pond occurred when Vectren South stopped sending ash before October 2015, which was prior to the effective date the CCR rule took effect. Pub. Ex. 1, p. 28, ll. 1-13.

Before the CCR rule came into effect, Vectren South had incurred and collected costs for ash disposal in its rates, as have all coal-burning utilities. Pub. Ex. 1, p. 28. While the CCR rule may have sped up the need for closure, Vectren South has not shown evidence regarding incremental costs that are in excess of pond closure costs previously included in rates. *Id.* As pointed out by Ms. Aguilar, "[t]hree other Indiana utilities are not tracking pond closure costs as Federally-Mandated CCR Projects." *Id.* pp. 28-29. In the absence of complete evidence supporting pond closure costs that meet statutory requirements, we will not approve Vectren South's request. Vectren South is obligated to show "[a]lternative plans that demonstrate that the compliance project is reasonable and necessary." Ind. Code § 8-1-8.4-6(b). Vectren South has not done so, and in the absence of complete information – including the pond closure costs Vectren South has collected in rates and compliance alternatives– we will not approve these projects.

C. Recovery of deferred costs authorized in Cause No. 44446

Vectren South has requested authority to recover costs incurred for MATS compliance, as previously approved in Cause No. 44446, through an environmental tracker denominated the ECA. Mr. Blakley and Ms. Aguilar reviewed Vectren South's request and had no objection to the requested recovery through the ECA. As with all environmental trackers, we anticipate that we and the OUCC will review Vectren South's filings to determine compliance with the Cause No. 44446 orders. We therefore find that Vectren South's request for an ECA to recover MATS costs as authorized in Cause No. 44446 is approved.

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

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is denied.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA shall be and hereby is approved as described in this Order.

4. Vectren South's proposed Environmental Cost Adjustment ("ECA"), and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA shall be and hereby is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED:

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

____

Mary M. Becerra
Secretary to the Commission

Attachment B

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ., 8-1-8.5-1 ET SEQ., AND 8-1-8.8-1 ET SEQ.	CAUSE NO. 45052

<u>ORDER OF THE COMMISSION</u>

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

TABLE OF CONTENTS

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity ("CPCN") for a new duct-fired F-class 2x1 combined cycle combustion turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. We convened a prehearing conference on April 3, 2018 and issued a prehearing conference order on April 11, 2018. Petitions to intervene were filed by (1) the Vectren Industrial Group; (2) Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); (3) the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); (4) SABIC Innovative Plastics Mt. Vernon, LLC, St. Joseph Energy Center, LLP, St. Joseph Phase II LLC, and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony.

On July 19, 2018 Joint Intervenors, the Coal Parties, Vectren Industrial Group, and the Office of Utility Consumer Counselor ("OUCC") filed a joint Motion for Partial Summary Judgment ("Motion") asking the Commission to determine as a matter of law that Vectren South's petition for a CPCN to construct a CCGT must be denied because no statewide energy analysis existed that satisfied the statutory criteria of Ind. Code § 8-1-8.5-3(a). On July 27, 2018, Vectren South filed its Preliminary Response and Partial Designation of Evidence in opposition to that motion. On August 3, 2018 the moving parties filed their Preliminary Reply to Vectren South's response and requested an expedited ruling holding the procedural schedule in abeyance. By Docket Entry of August 6, 2018, that request was denied and the date for Vectren South's formal response and evidentiary designation was set for August 20, 2018. On August 20, 2018, Vectren South filed is response and designation of evidence. On September 12, 2018, the moving parties filed their Reply in support of their motion and reply designation of evidence.

An evidentiary hearing was commenced on October 9, 2018. Before the first witness was called, Alliance Coal asked the Commission to rule on the Motion prior calling Vectren South's first witness, noting that the spirit of Trial Rule 56 is to narrow the issues in advance of trial. In the alternative, Alliance Coal requested the Commission continue the evidentiary hearing to allow the Commission to rule on the Motion. The Presiding Officers denied Alliance Coal's request, ordered the evidentiary hearing to proceed and stated the Commission would take the Motion under advisement and rule in the Commission's Final Order.

Thereafter, evidence was offered by Vectren South, the OUCC, the Joint Intervenors, the Vectren Industrial Group, and the Coal Parties, without objection. After Vectren South admitted its evidence into the record and rested its case, Alliance Coal moved to partially dismiss that portion of Vectren South's case requesting a CPCN for new generation pursuant to Indiana Trial Rule 41(B), 170 Ind. Admin. Code 1-1.1-12(3) and (5) and 170 I.A.C. 1-1.1-26. The Dismissal Motion was joined by the OUCC, CAC, Sierra Club, Valley Watch, ICC, and Sunrise.[1]

Vectren South presented its rebuttal evidence. Also, the OUCC, Coal Parties, Vectren Industrial Group, and Joint Intervenors cross-examined Vectren witnesses and admitted cross-examination exhibits into the record. The Commission, having heard the evidence and being duly advised, now finds as follows:

1. Notice and Jurisdiction. Due legal and timely notice of the prehearing conference, public field hearing, and evidentiary hearing in this Cause was given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Petitioner is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Petitioner may seek Commission approval of Certificates of Public Convenience and Necessity pursuant to the chapters. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding in the manner and to the extent provided by laws of the State of Indiana.

2. Petitioner's Characteristics and System. Petitioner is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Petitioner provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Petitioner's electric utility business. Petitioner renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages, and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light, and power for residential, commercial, industrial, and municipal uses. Petitioner furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois, and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five (5) coal-fired baseload units providing a total of approximately 1,000 MW: .B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick 4 (150 MW). Petitioner procures 100% of its coal supply from mines located

[1] The Vectren South Industrial Group did not join in the Trial Rule 41(B) Motion.

in Indiana. The other 248 MW of net generating capacity Vectren South owns and operates consist of 3 MW of land-fill gas generation, and 245 MW of natural gas fired peaking units: A.B. Brown 3 (80 MW), A.B. Brown 4 (80 MW), BAGS 2 (65 MW), Northeast 1 (10 MW), and Northeast 2 (10 MW). In addition, Vectren South has long term purchase power contracts for wind generated energy: Fowler Ridge (50 MW) and Benton County (30 MW).

Vectren South's operations are subject to federal, state, and local rules promulgated by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Evidence

A. Vectren South's case in chief

i. **Carl. L. Chapman**, Vectren South's President and CEO, provided an overview of Vectren South's proposed diversification of its generation fleet based on its 2016 Integrated Resource Plan (the "IRP"). He said that for decades, Vectren South has relied on its coal fired units to provide reliable service to its customers. In this case, Vectren South seeks authority to make environmental compliance investments to extend the life of Culley 3 because it is Vectren South's most efficient coal unit. Vectren South also seeks authority to invest in a new CCGT sized to replace the remaining coal units (A.B. Brown 1 & 2, Culley 3, and Warrick 4) that Vectren South proposed to retire (or, in the case of Warrick 4 withdraw from its contracts) at the end of 2023. Mr. Chapman said Vectren South considers its plan to be a reasonable transition in terms of why it is the appropriate time to plan retirement of these coal units. Mr. Chapman also stated this is why Vectren South considered its process in making these resource decisions thoughtful.

ii. **Jon K. Luttrell,** Senior Vice President of Utility Operations and President of Vectren Utility Holdings, Inc. testified that based on the 2016 IRP, the company determined the need to move forward with a process to diversify the generation fleet and replace aging coal units. He described the process Vectren South engaged in to select a CCGT to replace the retiring units and provide baseload generation to serve its customers' needs. Mr. Luttrell said that throughout 2017, with the assistance of external experts, Vectren South pursued three alternative paths to determine the best option to reliably serve customers. One alternative is based on a request for proposal ("RFP") the company issued to solicit competitive bids for either purchased power or ownership of all or a portion of a unit. Mr. Luttrell described the process used to analyze the RFP offers, and said that as a result of the RFP process, Vectren South was then able to compare the best competitive offer to several self-build alternatives at Vectren South's existing

A. B. Brown generation site, including a partnership alternative. He said that based upon an economic and qualitative comparison, he supports the decision to pursue building an approximately 850 MW CCGT at the existing Brown site.

iii. M. Susan Hardwick, Vectren South's Executive Vice President and Chief Financial Officer provided an overview of Vectren South's capital expenditure financing plan over the next several years and discussed the implications of that plan to the company. She emphasized the importance of supportive regulation in the execution of that plan.

iv. Wayne D. Games, Vice President of Power Supply, provided an overview of Vectren South's proposed diversification of its generation fleet based on its 2016 IRP. He echoed Mr. Chapman's testimony that for decades Vectren South has relied on its coal fired units to provide reliable service to its customers, and that in this case, Vectren South seeks authority (1) to make environmental compliance investments to extend the life of Culley 3, which is Vectren South's most efficient coal unit, and (2) to invest in a new CCGT sized to replace its other coal units which will be retired at the end of 2023. Mr. Games explained why Vectren South considers its proposal a reasonable transition in terms of why it is the appropriate time to plan retirement of most of its coal units. Mr. Games also explained why he considers the process used by Vectren South in making these resource decisions to be thoughtful.

v. Matthew A. Rice, Vectren South's Director of Research and Energy Technologies, explained Vectren South's 2016 IRP process, analysis, and results. He also explained the company's subsequent IRP modeling and analysis performed to support its request in this case.

vi. Matthew E. Lind, Associate Project Manager at Burns & McDonnell ("B&McD"), described the modeling B&McD conducted on behalf of Vectren South to evaluate its resource needs over the next twenty years. He also discussed B&McD's role in assisting Vectren South's solicitation of the RFP for energy and capacity. Finally, he described the modeling B&McD performed to evaluate the bids received in response to the RFP, including comparing the best bids to Vectren South's self-build CCGT alternatives.

vii. Gary Vicinus, Managing Director for Utilities at Pace Global, described the use of a balanced scorecard approach to modeling risk in Vectren South's 2016 IRP and certain modifications incorporated by Pace Global to address concerns raised in the Final Director's Report related to the scorecard.

viii. Rina H. Harris, Vectren South's Director of Energy Efficiency, described how part of the company's load obligation is met through Conservation and Demand Side Management ("DSM") initiatives (*e.g.* Energy Efficiency ("EE") and Demand Response). She testified that Vectren South has significant experience implementing EE programs. She also testified to the target level of EE that Vectren South's modeling indicated is the most economic, and that Vectren South is working diligently to achieve those targets. She described the revised EE modeling Vectren South performed for this proceeding. She also testified that DSM initiatives are not a realistic substitute for the CCGT for which Vectren South seeks a CPCN.

ix. Angila M. Retherford, Vectren South's Vice President of Environmental Affairs and Corporate Sustainability, testified about the federal and state environmental regulatory requirements that currently impact the company's electric generating units, and also about pending and proposed environmental regulations Vectren South is monitoring that Vectren South believes will likely have an impact on its generating units. She discussed the environmental compliance assumptions that Vectren South modeled in its 2016 IRP and its subsequent supplemental modeling. She explained how those assumptions have contributed to Vectren South's future resource planning, and how environmental regulations impacted that planning. She also explained certain federal mandates that will require Vectren South to make investments to comply at its Culley Generating Station.

x. Diane M. Fischer, Central Regional Area Director and Associate Vice President at Black & Veatch Corporation ("B&V"), testified regarding the engineering work completed by B&V related to (1) Vectren South's proposal to comply with the Effluent Limitation Guidelines ("ELG") in 40 CFR 423 that apply to Culley Generation Station through its renewed NPDES permit, and (2) Vectren South's proposal to install a new CCGT on the A.B. Brown plant site.

xi. Perry M. Pergola, Vectren South's Director of Gas Supply, described the interstate pipeline services Vectren South intends to secure to provide natural gas service to the proposed CCGT. He explained the planned location of that pipeline, and why Vectren South believes it is the least cost and most reliable source of gas for the proposed CCGT. He also discussed the negotiations that have taken place regarding the pipeline capacity along with the agreement in place to ensure gas will be available in a timely manner to the CCGT.

xii. Steven A. Hoover, Vectren South's Director of Engineering, described the cost estimate for the gas transmission line that Vectren South would construct to connect the proposed CCGT with Texas Gas Transmission, LLC's interstate pipeline.

xiii. J. Cas Swiz, Vectren South's Director or Rates and Regulatory Analysis, discussed Vectren South's proposed accounting and ratemaking treatment for (1) the proposed environmental compliance investments to extend the life of Culley 3, and (2) the completed investments approved in Cause No. 44446. He also discussed Vectren South's proposal to implement a rate adjustment mechanism, the Environmental Cost Adjustment ("ECA"), to recover these costs, and how those will be reflected as recoverable costs within the ECA Revenue Requirement calculation. Mr. Swiz provided Vectren South's proposed initial ECA rates and charges to recover the 44446 deferrals as of December 31, 2017, to be effective January 1, 2019. Mr. Swiz described the proposed allocation of costs and tariff sheet, as well as other proposed changes to Vectren South's Tariff for Electric Service. He also discussed the proposed adjustment to the authorized return amount utilized in the FAC net operating income earnings tests as a result of the proposed ECA. Mr. Swiz also discussed Vectren South's proposed accounting treatment for the proposed new CCGT.

xiv. Michael J. Hicks, the George and Frances Ball Distinguished Professor of Economics and Business Research and Director, discussed the analysis of the estimated economic effects of coal fired power plant closings in Indiana, performed by the Center for Business and Economic Research at Ball State University.

B. Cases in Chief of Indiana Office Utility Consumer Counselor and Intervenors.

i. Indiana Office Utility Consumer Counselor

a. Lauren M. Aguilar, Utility Analyst at the OUCC, recommended that the Commission deny Vectren South's requests for CPCNs for both the proposed CCGT and the Culley 3 Compliance Project. Ms. Aguilar presented a statutory analysis of the CPCN compliance statutes under Ind. Code chs. 8-1-8.5, *et seq.* for the CCGT and 8-1-8.4, *et seq.* for Culley 3 Compliance Projects. Regarding the CPCN request for the CCGT, Ms. Aguilar explained that Vectren South's evidence has not complied with three specific sections: (1) Ind. Code § 8-1-8.5-5(b)(1): providing the Commission with enough evidence to make a findings as to the best estimate of construction, purchase, or lease costs; (2) Ind. Code § 8-1-8.5-5(b)(3): providing evidence that the public convenience and necessity require or will require the construction, purchase, or lease of the facility; and (3) Ind. Code § 8-1-8.5-5(e)(1)(A): showing that the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable.

Ms. Aguilar stated the Indiana General Assembly in 2016 created Ind. Code § 8-1-2-0.5 to focus on the need for affordability when Indiana utilities plan for electric generation. Vectren South did not provide sufficient evidence for the Commission to properly consider this declaration. Ms. Aguilar also presented her concerns with the required Statewide Energy Analysis and IRP process pursuant to Ind. Code § 8-1-8.5-3. At the time of her testimony, there was only a Draft of the Statewide Energy Analysis which partially addressed issues in this case.

Ms. Aguilar stated the OUCC did not agree with the results in Vectren South's IRP process. She testified that the IRP is not a contested case where evidence is subject to discovery, cross-examination and the submission of verified testimony. As to the CPCN request for the Culley 3 projects, Ms. Aguilar explained Vectren South has been collecting ash pond closure costs in base rates and, as such, the ash pond closure should be treated as a general asset retirement. She also noted that Vectren South did not provide sufficient evidence to show the new process and storm water pond complies with Ind. Code § 8-1-8.4-6(b), as Vectren South did not provide an evaluation of alternative plans. Although Ms. Aguilar agreed the spray dry evaporator and drag chain conveyor requests comply with the CPCN statutes, she concluded that because Vectren South had not fully considered all options for its generation fleet, a proper evaluation might determine Culley 3 would not remain open. Such a determination would make the Culley 3 upgrades unnecessary, and she therefore recommended that the Culley 3 projects should also be denied.

b. Anthony A. Alvarez, Utility Analyst at the OUCC, testified regarding the system demand requirements to determine whether there was a need for Petitioner's proposed 850 MW CCGT. He reviewed Petitioner's Summer Reliability Outlook ("Summer Reliability") reports provided to the Commission, analyzed Petitioner's system load data and information from its responses to discovery, and then compiled the data to represent Petitioner's historical five-year (2013-2017) system peak load, total demand and reserve margin requirements. He testified that over the last five years (2013-2017), Petitioner's total demand and overall system requirements trended downward, while the Midcontinent Independent System Operator ("MISO") Planning Reserve Margin ("PRM") Requirements trended upward.

Mr. Alvarez testified that since 2013, Petitioner lost approximately 150 MW of total demand and its total system requirements decreased by approximately 135 MW. On average, Petitioner annually lost approximately 50 MW of total demand, total system requirements decreased by approximately 27 MW, and during the last five years, Petitioner's system did not experience any appreciable load growth. Mr. Alvarez testified that based on Petitioner's Summer Reliability reports, its negative load growth was due to the loss of firm wholesale customers in 2012, 2015, and 2017, when a customer decided to install its own large combined heat and power facility to serve its needs.

Mr. Alvarez testified that Petitioner forecasted an energy and demand growth of approximately 0.5% beyond 2019 in its 2016 IRP. In an April 7, 2016 IRP stakeholder meeting, Petitioner presented an updated forecast that showed it "expected demand to remain relatively flat through the forecast period (Compound Annual Growth Rate ('CAGR') is 0.1%)". Mr. Alvarez testified that a one-half of one percent load growth for Petitioner translated into approximately 5 MW of additional annual demand. Given Petitioner's recent annual load loss of approximately -50 MW and without evidence to the contrary, it was unrealistic to expect an annual addition of 5 MW of load. Mr. Alvarez testified that based on the results of his review and analysis, he did not find any system demand requirement or need to support Petitioner's proposed 850 MW CCGT unit.

Mr. Alvarez also reviewed Petitioner's supply requirements to determine whether it needed the proposed 850 MW CCGT unit. He compiled a five-year (2013-2017) historical generation and resources data set, using data and information from Petitioner's Summer Reliability reports to the Commission and responses to OUCC discovery. He compared Petitioner's total resources to its total demand and total system requirements to determine its capacity position in each year. Mr. Alvarez testified that for the period 2015-2017, Petitioner's "excess" supply and its "long" capacity position trended upward because its total demand losses were greater than the overall decline in its total resources. He stated that even though Petitioner lost approximately 150 MW of demand from 2013 to 2017, due to de-rates its resources only declined by approximately 55 MW.

Mr. Alvarez testified that even without the capacity credit of Broadway 1, Petitioner maintained a long capacity position in the last five years. Mr. Alvarez testified that each year, MISO conducted generator verification tests, collected unit-specific data and applied necessary forced de-ratings to determine the generating unit's Unforced Capacity ("UCAP") rating. He stated that the reductions, or de-rates, of A.B. Brown units' UCAP ratings were the results of these tests, as were the slight increases in the overall UCAP ratings of Petitioner's gas generation units. He testified that aside from the retirement of Broadway 1, the net effect of A.B. Brown's de-rates contributed much to the overall decline in Petitioner's total resources for 2017.

Mr. Alvarez testified that for the last five years, Petitioner maintained excess supply after serving its peak load and remained long in its capacity position after covering its MISO PRM requirements, even though its total resources were declining. He explained that as Petitioner's demand decreased, its excess capacity would increase and would allow Petitioner to offer more capacity into the market. Thus, he concluded Petitioner has more than enough capacity to serve its own load and could still sell excess capacity into the market and provide service to new customers (wholesale, large industrial, commercial) that would enter its service territory. Further, he testified that Petitioner has the capacity to cover additional MISO reserve margin requirements should the need arise in the near future. Mr. Alvarez testified that Petitioner's resources were adequate to serve its load, and it has no resource shortfall to support its proposed 850 MW CCGT unit. He concluded that it was therefore imprudent for Petitioner to shut down power plants to justify the need for a new 850 MW CCGT unit.

Mr. Alvarez discussed Mr. Chapman's direct testimony that Petitioner's generation diversification strategy included the retirement of four of its five coal generating units, three of its five gas generating units and replacement of the retired units with one gas unit. Mr. Alvarez testified the Petitioner's proposal retired approximately 65% (833 MW) of its current generation fleet capacity and replaced it with one 850 MW CCGT unit. While Petitioner's coal units represented approximately 77% (1,000 MW) of its generation capacity, its gas units represented approximately 20% (259 MW). Mr. Alvarez testified that if Petitioner built its proposed new 850 MW CCGT and retired its current units, its capacity position by fuel mix would reverse itself, with gas generation representing approximately 77% and coal generation representing approximately 20%. Mr. Alvarez testified that of the current generating units, only the F.B. Culley 3 coal unit (270 MW) and the A.B. Brown 3 and 4 gas units (174 MW) would remain operational. Petitioner consolidated its generation fleet in favor of gas and a single large CCGT unit, which overhauled and dismantled the multi-unit, multi-fuel, and multi-technology backbone of its current generation portfolio. He testified that Petitioner's strategy shifted too much risk onto its ratepayers, by including a gas-dominated generation fuel mix and a single-unit, single-technology dominated generation portfolio. Mr. Alvarez questioned whether Petitioner's generation diversification strategy mitigated its customers' risk and quoted Mr. Chapman:

> While switching entirely to gas-fired generation might have the lowest net present value ("NPV") from a modeling perspective, such a single fuel portfolio would lack diversity, and therefore, introduce risk to customers if gas prices or other assumptions embedded in the model that favored gas turn out to be wrong.

Direct testimony of Carl Chapman, at 7.

Mr. Alvarez said that while Mr. Chapman testified about how "a single fuel portfolio would lack diversity" and would "introduce risk to customers," Mr. Chapman's diversity strategy would create a higher degree of risk to its ratepayers by exposing them to a generation fuel mix dominated by a single fuel—gas (77%)—and exposing them further to a generation fleet dominated by a single-unit –a 850 MW CCGT.

Mr. Alvarez stated that Petitioner's decision to build a new 850 MW CCGT is premature. He recommended Petitioner explore practical alternatives that would extend the lives of its existing A.B. Brown units to mitigate the major risks inherent in Petitioner's strategy. He also recommended Petitioner explore cost effective alternatives that did not require intensive capitalization. Mr. Alvarez testified that if Petitioner was seeking generation diversity, it should not build an 850 MW CCGT unit that consolidated its resources rather than diversified them. He explained that although Petitioner's 2016 IRP preferred portfolio chose a CCGT, he recommended Petitioner not limit its options to that conclusion, which would commit Petitioner and its ratepayers for the next 40 years. Finally, Mr. Alvarez recommended the Commission require Petitioner to include practical alternatives in its 2019 IRP stakeholder process. He stated that Ms. Aguilar identified alternatives Petitioner should further explore and discussed these alternatives from an environmental perspective, while Dr. Boerger discussed the economics of the alternatives.

Mr. Alvarez testified that while Petitioner issued an RFP, it only solicited bids to serve Petitioner's stated need for 800+ MW of capacity, not for the building of the CCGT. Therefore, he concluded, the current estimate of $781 million for the building of the CCGT did not meet the requirements of Ind. Code § 8-1-8.5-5(e), which requires competitive construction bids. Mr. Alvarez testified that if Petitioner reevaluated its resource portfolio during its 2019 IRP, it would leave sufficient time for implementation by 2023, as most of Petitioner's environmental compliance deadlines were in either the mid 2020s or 2023.

Mr. Alvarez also verified the capacity of each unit that Petitioner proposed to retire and found the 60 MW ICAP capacity of Broadway Avenue Gas Station ("BAGS") Unit 1 was included in its calculations. He explained that BAGS 1 has not received any capacity credit from MISO since 2014, which made it inappropriate for Petitioner to include the capacity to support its proposed 850 MW capacity CCGT. See, Alvarez direct fns. 8 & 10, pp. 6-7. Mr. Alvarez testified that without BAGS 1, Petitioner's proposed capacity retirement dropped down to 815 MW ICAP. He stated that any capacity retirement or replacement decision should take into consideration a generator's (retired and replacement) UCAP rating because it represented: (1) the effective capacity of resources taken out (or retired) from the system and (2) the generator's actual capability to respond to demand. He explained that in the case of a brand new 850 MW CCGT unit, its forced outage or forced de-rate would be minimal, so its ICAP and UCAP ratings would be similar. Mr. Alvarez testified that by comparison, Petitioner's proposed capacity retirement would be 725.40 MW UCAP.

Mr. Alvarez testified that Petitioner did not provide sufficient support for its proposed retirement of BAGS 2 in 2025. In response to discovery, Petitioner stated that "BAGS Unit 2 is currently 37 years old and beginning to show signs of age but still starts reliably when needed. In the 2016 IRP[,] Vectren South projected that this unit would be retired in 2025 due to age (44 years old), repair costs and low capacity factor due to its inefficient operation." Att. AAA-2. Mr. Alvarez testified that a utility should not retire an asset simply because it was "beginning to show signs of age," especially if the asset "still starts reliably when needed." He explained that Petitioner was responsible for keeping its assets in good operating condition, operating efficiently, and attaining higher capacity factors. Mr. Alvarez testified that Petitioner did not provide any evidence that the BAGS Unit 2's inefficient operation was causing repair costs and low capacity factors so severe to support its decision to retire BAGS Unit 2 in 2025.

Mr. Alvarez testified Petitioner's proposed capacity retirement and replacement would provide Petitioner a surplus of approximately 125.50 MW (17.30% UCAP). If the Commission approved the proposed 850 MW CCGT, but Petitioner's load growth remained negative or even stayed flat by 2023, Petitioner would double its excess capacity at great cost to its ratepayers, as discussed by Dr. Boerger. Mr. Alvarez testified that Vectren South did not have the demand requirements to justify its proposal for new and additional capacity. By retiring several generating units, Vectren South could prove it did not have enough resource requirements and thus needed to construct its proposed 850 MW capacity CCGT unit. Mr. Alvarez testified that this was a very risky play for a small utility such as Vectren, and even more risky for Vectren South's customers.

Mr. Alvarez stated that he did not agree with Mr. Chapman's statement that Vectren South was retiring comparatively small coal units that were not competitive and inefficient. Mr. Alvarez testified that Petitioner's coal units are utility-scale generators and the A.B. Brown coal units slated for retirement have an installed capacity rating of 245 MW each, while the F.B. Culley 3 coal unit (which Vectren South plans to keep) has an installed capacity rating of 270 MW. He stated that A.B. Brown was the larger generating station with a total capacity of 450 MW; the F.B. Culley station was smaller with a total capacity of 360 MW (including the 90 MW F. B. Culley 2). Mr. Alvarez testified that the sizes of these generating units provided Vectren South the flexibility and balance it required to serve its load effectively if it needed to take a unit offline (forced or planned).

Mr. Alvarez explained that a unit's capacity factor provided a good measurement of a generator's overall competitiveness, efficiency and performance in the marketplace, defined by the U.S. Energy Information Administration as "[t]he ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period." Mr. Alvarez testified that compared with the performance of the U.S. coal fleet from 2013 through 2017, Vectren South's coal units performed at par in some years, and even better in other years, than the entire coal fleet of the country. Mr. Alvarez testified that Petitioner's three coal units outperformed the U.S. coal fleet during the polar vortex event in 2014, during which there was unprecedented peak demand across the eastern U.S. and the Midwest.

Mr. Alvarez testified that Petitioner identified a wet flue gas desulfurization ("FGD") technology as a viable replacement for the dual alkali scrubbers at A B. Brown, but only evaluated the wet limestone, forced-oxidation method. Mr. Alvarez testified that Mr. Chapman dismissed the opportunity for Vectren South to explore other replacement alternatives and concluded "it makes more sense to retire these [A.B. Brown] units and invest in new CCGT technology." Mr. Alvarez testified that Vectren South needed to provide support exploring all cost-effective options that could extend the life of the generating units. He explained that Mr. Chapman stated that the replacement cost for the dual alkali scrubbers was approximately $340 million; Vectren South's consultant, B&McD, provided a high-level cost estimate breakdown for a wet FGD with a total project cost of $299 million.

Mr. Alvarez testified he evaluated the viability of other technologies that would extend the useful life of the A.B. Brown units, including coal-to-gas conversion technology as modeled by Babcock & Wilcox ("B&W"). Mr. Alvarez researched B&W's technology for the conversion of power boilers to gas; compiled the engineering, performance and cost estimate information from Vectren South's technical studies; and compared this information with the initial results he gathered from recently completed coal-to-gas conversion projects here in Indiana. Mr. Alvarez said that the B&W coal-to-gas technology was a viable alternative that would extend the useful life of the A.B. Brown units. He reviewed the conceptual engineering design by B&McD evaluating the feasibility of a coal-to-gas conversion project at A.B. Brown (revisions dated September 2015 and February 2016). Mr. Alvarez testified that emissions issues could be solved with engineering and therefore he did not anticipate that the gas conversion would have emissions issues.

Based on the initial performance results of recently completed IPL Harding Street gas-conversion projects where the units retained existing SCRs and installed FGRs as well, Mr. Alvarez testified IPL did not need to operate the SCRs at all. Mr. Alvarez testified that based on IPL's Harding Street projects, he did not expect a de-rate of the A.B. Brown generating units after a conversion to gas, as the three coal-fired boilers achieved full load operation at high Maximum Continuous Rating percentages when firing 100% gas. He explained that the initial thermal input analysis of these boilers showed that proper configuration of gas burners and ignitors at previous coal elevations could produce a slight excess in thermal energy and increase the furnace heat input. The IPL gas conversion also lifted the parasitic load of emission control devices off the unit and added to its capacity, and Mr. Alvarez expected a similar outcome with a gas conversion of A.B. Brown.

Mr. Alvarez stated that he verified B&McD's estimate and project scope for the gas conversion of both A.B. Brown units. He said that Vectren South's gas conversion estimate was a very low capital cost for a technically viable option to extend the useful life of the A.B. Brown units, and Vectren South should have allowed its Strategist model to select this option. Compared to a CCGT, repowering the A.B. Brown units with gas was a viable option at a fraction of the proposed

CCGT's cost. He concluded that extending the life of existing assets at a very low capital cost using proven technology provided greater service to ratepayers.

Mr. Alvarez testified that Vectren South's high-level cost breakdown for the proposed CCGT was not a result of competitively bid engineering, procurement, or construction contracts as required by statute. He testified that Vectren South based the cost estimate for its proposed CCGT on the conceptual design developed by its consultant and did not competitively bid the "engineering" scope "because it is not commercially practicable to do so." Mr. Alvarez quoted Mr. Games' testimony, Direct at 15, Line 8, that the estimated cost of "$781 million (+/- 10%)" is an "anticipated cost." Mr. Alvarez explained that at a capacity rating of 850 MW, Vectren South's estimate represented a cost of approximately $919 per kilowatt ("kW"). However, Mr. Chapman testified the cost estimate included an additional 150 MW for a duct firing option at a "very low upfront cost" of approximately $15 million. Mr. Alvarez explained that this meant the base configuration of Vectren South's proposed CCGT has a capacity rating of only 700 MW for $766 million, or a "per unit" cost of approximately $1,095 per kW. Mr. Alvarez testified that by comparison, Vectren South's estimate to convert the A.B. Brown units to gas was $130 per kW.

Mr. Alvarez explained that Vectren South has not selected its equipment manufacturer and sought bids for its proposed CCGT turbines. He stated that Petitioner foresees specification deviations, design changes and technology advances at the (future) time of the "final competitive bidding." Mr. Alvarez testified that as a result, Vectren South would not finalize its procurement process until after the Commission issues Vectren South a CPCN. Given the conditions laid out by Messrs. Games and Chapman in their respective testimonies, Mr. Alvarez stated it was unrealistic that Vectren South could complete this project on time and on budget because there were too many unknowns.

Mr. Alvarez reviewed the "EPC Basis of Estimate for the F-Class Configuration (Confidential)" provided by Ms. Fischer that corresponded to the CCGT design type identified by Messrs. Games and Chapman. He stated that components of the cost estimate further supported the OUCC's uncertainty of Petitioner's cost estimate. Mr. Alvarez testified that it was Petitioner's responsibility to provide enough support for its proposal and if Petitioner's consultant cannot stand behind its own cost estimate without any qualifications, the OUCC cannot support Petitioner's cost estimate proposal. He concluded these conditions raised "red flags", signaled the potential for price escalation and construction schedule delays down the line, and exposed Vectren South's ratepayers to a high degree of risk.

Mr. Alvarez testified that Petitioner's $781 million estimate also did not include costs for the lateral pipeline it also sought authority to build. According to Vectren South witness Steven Hoover, the estimated cost of the pipeline is $87 million, but that estimate was an AACE Class 2 estimate, indicating a +/- 20% level of confidence. Therefore, using Vectren South's own calculations, the cost of the pipeline could be as low as $69.6 million (-20%), or as high as $104.4 million (+20%). He testified that this cost to customers would be in addition to the cost of constructing the CCGT, potentially making the total cost for the CCGT as high as $885,400,000 ($781,000,000 + $104,400,000). Mr. Alvarez testified that the cost estimate Petitioner provided for its CCGT was not a result of competitively bid engineering, procurement, or construction contracts as required by statute. He explained that with a base configuration cost of approximately $1,095 per kW, Petitioner should evaluate other cost-effective alternatives, such as a $130 per kW gas conversion option for the A.B. Brown units. He stated that Petitioner should refine and support its cost estimate and address all the "red flags" in its proposed cost estimate that signaled price escalation, construction-scheduling uncertainty, and lack of general confidence in its ability to undertake projects of this magnitude. Finally, he concluded that Vectren South should shield and protect its ratepayers from this risk.

c. Peter M. Boerger, Senior Utility Analyst in the Electric Division of the OUCC, presented his analysis of Vectren South's proposal and review of Vectren South's economic modeling. He said his analysis shows that Vectren South's proposal did not adequately consider viable options for serving its customers — including making use of existing resources and adequately considering the addition of a smaller CCGT rather than the large unit being proposed. He also determined that Vectren South's economic modeling of the proposed CCGT understated its capital cost by $200 million, an error that disadvantaged other options in Vectren South's economic modeling. Dr. Boerger provided the OUCC's recommendation that, given the significance of this case, Vectren South should reevaluate its future needs, including the full cost of resource alternatives in its modeling, such as a smaller CCGT, or refueling its Brown Unit(s), and Vectren South should more fully consider continued use of its existing assets.

d. Wes R. Blakley, Senior Utility Analyst, testified as to Vectren South's proposed accounting and ratemaking treatment of its pollution control projects and its CCGT project. He addressed Vectren South's request to establish a new rate recovery mechanism, identified as the ECA, for recovery of costs related to two pollution control projects. He also reviewed and commented on Vectren South's request for accounting and ratemaking treatment pertaining to its CCGT project.

Mr. Blakley stated that the OUCC has no concerns with the ECA tracker mechanism proposed by Vectren, if the costs comply as certified costs per the Federally Mandated Statute under Ind. Code ch. 8-1-8.4. He stated that the OUCC does not waive the right to question the recovery of certain costs, accounting treatments, or policies adopted by Vectren South in its tracker proceedings. He stated OUCC witness Lauren M. Aguilar recommends that costs associated with the

MATS Compliance Project be permitted recovery through the ECA tracker, but costs associated with the Culley 3 Compliance Project be denied recovery.

Mr. Blakley expressed concerns with the post-in-service cost recovery related to the CCGT project, specifically the carrying charge used to accrue capital cost on the CCGT once it is in service. Mr. Blakley stated that Vectren South believes that the weighted average cost of capital ("WACC") rate should be used to record post-in-service carrying charges. Mr. Blakley explained that the Allowance for Funds Used During Construction ("AFUDC") rate should be used as a carrying charge to accrue capital costs on capital projects after they are in service. Mr. Blakley stated that the statutes that govern trackers, such as the federal mandated tracker, Ind. Code ch. 8-1-8.4 and the transmission, distribution, and storage charge ("TDSIC") tracker under Ind. Code ch. 8-1-39, require deferral of 20% of all costs. He explained that both of these statutes refer to the rate with which a capitalized carrying costs should be deferred as "post in service charge based on the overall cost of capital most recently approved by the commission shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission." Ind. Code § 8-1-8.4-7(c)(2). The carrying charge rate previously used on the 20% deferral under these statutes has been the WACC rate. Mr. Blakley testified that the AFUDC rate is used to capitalize costs to construction projects either during construction or post-in-service, not the WACC rate. He stated that the purpose of WACC is in the calculation of a return on investment, which creates the bottom-line earnings that are grossed-up for federal income taxes.

e. **Barbara A. Smith,** Executive Director of Technical Operations at the OUCC, testified that the OUCC had concerns regarding the Draft Statewide Analysis in its then-current state because it contained ambiguities, which made the consequences of the analysis and its conclusion difficult to determine. She stated the purpose of her testimony is to summarize the concerns the OUCC and other stakeholders' ("Joint Stakeholders") have regarding the Draft Statewide Analysis. Ms. Smith stated these stakeholders were developing joint comments to be submitted on August 17, 2018, per GAO-2018-2 and moved for leave to attach these comments to her testimony in this Cause once they were filed with the Commission in the GAO proceeding.

Ms. Smith testified that Ind. Code § 8-1-8.5-3 addresses the Commission's "analysis of needs; plans; hearing; [and] report" for the specific findings the Commission must make in granting a CPCN. She emphasized that this statute states "the commission shall develop, publicize, and keep current and analysis of long-term needs for expansion of facilities for the generation of electricity." Ms. Smith also pointed to what must be included in the analysis pursuant to Ind. Code § 8-1-8.5-3(b), and that Ind. Code § 8-1-8.5-3(c) states "[t]he commission shall consider the analysis in acting upon any petition by any utility for construction."

Ms. Smith stated the parties should be provided the opportunity to review a completed Statewide Analysis and provide testimony regarding it in this Cause. She testified that a draft does not provide the proper foundation for decision-making regarding Indiana's generating resource needs.

Ms. Smith pointed to page 28 of the Draft Statewide Analysis that discussed Vectren South's request for relief in this Cause. She testified that the Commission was not just stating a fact, which is evident when other portions of the Draft Statewide Analysis, such as footnote 3, are considered: "The Commission considers a robust stakeholder process essential to understanding and expediting cases by narrowing a number of contentious issues." She stated that although the non-utility parties devote resource time to the IRP stakeholder process, they typically do not have access to the utility's models and therefore it is unknown the extent their input is reflected in the final IRP. Given the Commission's stated confidence in the IRP stakeholder process and the mention of the Vectren South CPCN in its Draft Statewide Analysis, it cannot be determined how much weight the Commission has given Vectren South's IRP conclusion regarding the CPCN.

Ms. Smith stated the common thread in each of the OUCC's concerns is the need for clarification as to the consequences of the analysis' conclusions. She listed the concerns, which she stated would be fully explained in the Joint Stakeholders' Draft Statewide Analysis comments.

Ms. Smith testified that the Commission has authorized CPCNs before without the prior issuance of a statewide analysis, but the current proceeding is different because of the pending draft. She stated this case would be best resolved after the analysis is complete so the Commission could incorporate the analysis into its CPCN decision.

ii. Intervenor Alliance Coal

a. Michael J. Nasi is a partner with the law firm of Jackson Walker, L.L.P. that has practiced before state and federal environmental and energy agencies and appellate courts for more than 23 years. Mr. Nasi challenged Vectren South's claim that environmental regulations require Vectren South to move now to retire its coal assets and build the proposed CCGT. Mr. Nasi provided the context, recent history and anticipated changes to relevant environmental rules, which he testified Vectren South has not properly considered. He observed that Vectren is ill-advised not to factor in anticipated changes to the regulatory landscape and noted that the issue is not one of suspension of compliance activities but rather what compliance will mean in the near term. He testified that the environmental regulatory landscape is not presently sufficiently defined to justify a major strategic decision regarding Vectren South's fleet, let alone one that effectively wastes ratepayer dollars by prematurely retiring a well-functioning, paid-for asset while expending significant new capital on a generation technology much more susceptible to fuel volatility than the already-paid-for assets.

Mr. Nasi first provided a history of the development and evolving status of the EPA's ELG regulations, which were first promulgated in 2015 and codified at 40 CFR Part 423 (the "2015 ELG Rule"). The ELG rule generally applies to stream electric power plants that use fossil fuels or nuclear energy to heat water in boilers. Relevant to Vectren South's Petition, the ELG rule regulates six types of waste streams: fly ash transport water, bottom ash transport water, FGD wastewater, flue gas mercury control wastewater, gasification wastewater, and combustion residual leachate. For existing sources that discharge directly to surface waters (except for oil-fired generating units and those with nameplate capacity of 50 MW or less), the rule establishes effluent limitations for the referenced waste streams based on Best Available Technology Economically Available ("BAT"). The requirements of the rule, which differs depending on the waste stream in question, applies "as soon as possible" beginning November 1, 2018, but no later than December 31, 2023.

Mr. Nasi explained that EPA received several petitions for review of the 2015 ELG Rule and they were consolidated in the U.S. Court of Appeals for the Fifth Circuit. *Southwestern Electric Power Co., et al. v. EPA*, No. 15-60821. On August 11, 2017, EPA announced its intentions to conduct a rulemaking to potentially revise certain BAT effluent limitations for FGD wastewater and bottom ash transport water. On August 14, 2017, EPA filed a motion to govern further proceedings in the U.S. Court of Appeals for the Fifth Circuit. Subsequently, on September 18, 2017, EPA published a final rule entitled "Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category." This is commonly referred to as the "Postponement Rule." In this Postponement Rule, EPA postponed the earliest compliance dates for the new, more stringent, BAT effluent limitations for FGD wastewaters and bottom ash transport wastewaters listed in the 2015 ELG Rule for a period of two years. Therefore, this postponement moves the "as soon as possible date" from November 1, 2018 to November 1, 2020.

In the Postponement Rule, Mr. Nasi observed that EPA projected that it will finalize a new rule by Fall 2020 (82 Fed. Reg. 43498), and EPA further stated that if it does not complete a new rulemaking by November 2020, "it plans to further postpone the compliance dates such that the earliest compliance date is not prior to completion of a new rulemaking." 82 Fed. Reg. 43498, FN 6. In its document entitled *Final 2016 Effluent Guidelines Program Plan* dated April 2018 (EPA-821-R-18-001), EPA states that a proposed rule is expected to be published in December 2018, and a final rule in December 2019.

Mr. Nasi testified that the Postponement Rule specifically allows entities to make the case for extending deadlines to December 31, 2023. He noted that nothing prevents Vectren South from going before IDEM and requesting that the applicability date be determined whenever EPA publishes the new rulemaking in regards to bottom ash transport water and FGD wastewater. Mr. Nasi emphasized the importance of this option given its significance to Vectren South's compliance strategy. Thus, it is possible that no deadline, not even the December 31, 2023 date, will ultimately be imposed in the company's NPDES permit. Mr. Nasi pointed out that Vectren South overlooks its ability to obtain relief afforded to it by the Postponement Rule and incorrectly asserts that the company "must complete" the bottom ash conversion by December 31, 2020. He also noted that Vectren South's compliance strategy to construct a spray dryer evaporator system may be unnecessary particularly if the main purpose is to obtain a December 31, 2023 deadline. The Postponement Rule allows for this outcome without the need to convert the system to a no discharge system.

Next, Mr. Nasi described the 2015 Coal Combustion Residual ("CCR") Rule, promulgated in 2015 and regulating existing and new CCR landfills, existing and new CCR surface impoundments and all lateral expansions of the CCR units. The minimum national standards include location restrictions; design and operating criteria; groundwater monitoring and corrective action; closure requirements and post closure care; and recordkeeping, notification and Internet posting requirements. Mr. Nasi explained that the 2015 CCR Rule did not require facilities to obtain a federal or state permit, nor did it establish any requirements on states or state programs. He noted that EPA did not believe that it had the authority under RCRA to require as such. As a result, it was a self-implementing program meaning that owners/operators of facilities regulated under the rule could comply with the federal minimum criteria without the need to interact with a regulatory authority. Mr. Nasi testified that the requirements of the CCR Rule are enforceable under RCRA's citizen suit authority.

Mr. Nasi testified that the 2016 Water Infrastructure Improvements for the Nation ("WIIN") Act authorized states to implement the CCR Rule through an EPA-approved permit program. WIIN allows states to submit a program to EPA for approval that can operate in lieu of the federal requirements. To be approved, a state program must require each CCR unit to achieve compliance with the federal regulations, or alternative state criteria that are "at least as protective" as the federal regulations.

Mr. Nasi described pending changes to the CCR rule. The March 2018 CCR Rule amendment, referred to as "Phase One" proposed two general categories of changes: 1) language associated with a judicial remand in connection with a settlement agreement that resolved four claims brought by two sets of plaintiffs against the 2015 CCR Rule; and 2) revisions responsive to the WIIN Act. EPA also proposed several provisions to provide states and the EPA with permit program flexibility. In July, 2018, EPA published a final rule amending the 2015 CCR Rule by including some of the flexibilities referenced in its rule proposal. This is referred to as "Phase One, Part One." Mr. Nasi testified that the Phase One, Part One rule generally: (1) allowed states with approved CCR permit programs under the WIIN Act or EPA where EPA is the permitting authority to use alternate performance standards; (2) revised the groundwater protection standard for constituents which do not have an established drinking water standard; and (3) extended the deadline by which facilities must cease the placement of waste in CCR units in certain circumstances. Among the extensions is a new October 31, 2020 deadline for facilities with statistically significant groundwater protection standard increases from unlined CCR surface impoundments.

In addition to these changes, Mr. Nasi testified that EPA is considering additional changes to significant portions of the 2015 CCR Rule. Beyond what was proposed in the March 2018 proposal, EPA is also considering changes in a second phase which are anticipated to be completed by December 2019. Mr. Nasi stated that Phase Two changes are expected to include reconsideration of the CCR Rule's authority to regulate "inactive" ponds, potential inclusion of risk-based components in groundwater remediation, and changes to the requirement to close unlined units in certain situations.

Mr. Nasi testified that it is difficult to imagine how the reconsideration of the CCR Rule would not have a significant impact on Vectren South's compliance plans given the possibility that the CCR rule refinements could further adjust compliance deadlines, exempt "inactive" units from federal regulations, and modify the requirement to close unlined units (or significantly alter corrective action measures). Mr. Nasi observed that although Vectren South witness Retherford claims that the Culley East and Brown ponds must initiate closure in 2019, this deadline has already been extended by the July 2018 CCR Rule amendment. Additionally, he stated that if the requirement to close unlined units is further revised so as to require corrective action, but not necessarily require "closure" of the unit, then the fate of these ponds changes altogether.

Mr. Nasi disagreed with Vectren South witness Retherford's opinion that closure of CCR units would be required independent of the ELG or CCR regulatory requirements as a result of litigation over surface water pollution from ash pond groundwater contamination. He cited several cases that evidence a split of opinions among courts on the issue. Because of this split in opinions, Mr. Nasi testified that EPA published a proposed rule in February, 2018 seeking comments on its prior statements related to this issue. Mr. Nasi observed that the determination of whether there is a direct hydrologic connection between groundwater and surface water such that a release to groundwater would constitute a discharge of a pollutant to the waters of the United States is a fact-specific inquiry. He stated that nothing in the record of this proceeding suggests that (1) such a connection exists, (any potential connection would actually trigger actionable contamination), (2) an aggrieved party with standing could sustain a Clean Water Act citizen suit, or (3) the ultimate outcome of this theoretical litigation would justify Vectren South's proposal. Even if liability was conceivable, Mr. Nasi testified that it seems a slippery slope to allow a utility to justify massive capital expenditures based on theories of liability that depend upon multiple contingencies, none of which are supported in the record.

Mr. Nasi also testified to the relevance of grid resilience to Vectren South's proposal, given that Vectren South proposes to prematurely retire highly resilient coal fired generation and replace it with much less resilient gas fired units. He defined grid resilience as the ability of a given electricity grid to withstand dramatic weather events or other extreme situations that might otherwise put in jeopardy the ability of the bulk power system to meet the needs of residential, commercial, and industrial customers without subjecting them to a loss of power and/or extreme economic hardship.

Mr. Nasi referenced the March, 2018 comprehensive study released by the Department of Energy's National Energy Technology Laboratory ("DOE/NETL") which he said makes it clear that coal units such as those proposed to be prematurely retired, continue to impart a significant resilience benefit to the bulk electric power system relative to both non-dispatchable renewables and other resources, such as natural gas-fired power plants, which are more susceptible to interruption due to climate, weather or third-party physical or cyber-attacks. According to Mr. Nasi, the clear conclusion of the DOE/NETL study is that during extreme weather events, grid resilience is enhanced by coal, impaired by non-dispatchable generation such as wind and solar, and often not benefited by natural gas-fired generation.

Given the magnitude of costs involved and the fact that ongoing regulatory reforms could significantly reduce those costs, Mr. Nasi concluded that it is premature for Vectren South to move forward with its coal unit retirements at this time. He observed that once these highly resilient units are retired, it becomes an irreversible decision. By waiting until ongoing regulatory reforms are better understood, he testified that Vectren, the Commission and all stakeholders will have a better understanding of the regulatory costs faced by Vectren South and, therefore, the advisability of its current proposal.

b. Jude T. Clemente, Principal at JTC Energy Research Associates, LLC is an energy analyst with a particular focus on energy/electricity prices and the impact of higher cost energy. Mr. Clemente's testimony refuted Vectren South's natural gas price assumptions; Vectren South's claim that natural gas is more efficient than coal; and Vectren South's presumption that natural gas prices are falling. Mr. Clemente observed that Vectren South's plan is shortsighted and based on the non-guarantee that natural gas will remain cheap forever.

Mr. Clemente raised concerns that ongoing and likely transformative future changes in the U.S. natural gas market are not being properly considered by Vectren South. He also noted that Vectren South does not appear to consider the growing effort by groups to slow or cancel natural gas pipeline builds. Mr. Clemente noted that nationally, as coal plant retirements continue and utilities move to only renewables and gas, there is no backup plan if gas prices rise.

Mr. Clemente observed that Indiana is not a gas producer, and gas-importing states often have much higher rates. He noted that there are far more bullish factors in the gas market today than bearish factors, and LNG exports will increasingly put a floor on our market and force importing U.S. states to compete globally for supplies. Additionally, the only gas producers in proximity to Indiana are in Ohio, West Virginia and Pennsylvania and are relied upon greatly by other states. Thus, Mr. Clemente expects that Indiana's gas supply will become more difficult and competitive in the years and decades ahead.

Mr. Clemente testified to several natural gas future price risks that Vectren South failed to consider, including: 1) that natural gas is currently an undervalued commodity with a much stronger upside than downside; 2) natural gas exports are the single biggest incremental demand market in the U.S.; 3) as electric vehicles and anti-oil laws proliferate, a significant decline in oil demand and therefore prices could lower "associated gas" production (the natural gas that comes as a byproduct of oil production), which now accounts for nearly 25% of total U.S. gas supply; 4) new pipeline projects are frequently delayed or canceled amidst activist challenges; 5) new regulations could slow U.S. gas production in the span of a single election cycle,; 6) lack of new gas storage capacity adds price volatility, especially as LNG exports grow to capitalize on demand and price swings in foreign markets; 7) there is surging competition for natural gas supplies across the country; and 8) the potential for methane regulation is a concern for those seeking to use more natural gas because gas is 95% methane.

Mr. Clemente also testified to the threat to reliability of total reliance on natural gas and renewable energy as compared to a diverse fuel portfolio that includes coal. He referenced the 2014 Polar Vortex and January 2018 Bomb Cyclone crises, where coal was the go to source of power because it was stored on site and available during extreme cold temperatures. He noted that natural gas storage is highly expensive and storage capacity has not kept up with natural gas production. Mr. Clemente testified that the North American Electricity Reliability Corporation has also cautioned that increasing dependence on natural gas for electricity generation could pose reliability risks to the bulk power system due to the reliance on a single, just-in-time fuel source.

Mr. Clemente stated that higher energy prices caused by over reliance on natural gas will harm Indiana consumers, businesses and industry. By contrast, he stated that declining demand for coal will lower energy prices that use coal as a fuel source. With these considerations in mind, Mr. Clemente testified that

Indiana customers could face higher rates and decreased reliability if Vectren South's proposal is approved. Ultimately, Mr. Clemente recommended that Vectren South's proposed coal-to-gas switch should be paused to better consider the permanent ramifications because decisions made today will be felt well into the 21st century. He testified regarding the potential cost impacts of Vectren South replacing most of its coal fleet with a CCGT, given the uncertainty concerning domestic U.S. natural gas market in the years ahead, and a variety of factors that could increase prices more than expected.

iii. Intervenor Indiana Coal Council

a. Emily Medine, Principal at Energy Ventures Analysis, Inc., testified on behalf of the ICC on various issues regarding Vectren South's case.

Ms. Medine questioned Vectren South's assertion that its decision in this case was driven in part by its need to comply with the current EPA's Steam Electric Power Generating ELG Rule by the current 2023 deadline. Ms. Medine testified that the current ELG Rule was published in the Federal Register on November 3, 2015, and was timely appealed. In August 2017, EPA announced a new rulemaking that may revise the 2015 ELG Rule as it applies to bottom ash transport and FGD wastewater. Ms. Medine testified that EPA projects the Proposed Rule will be filed in December 2018 and the Final Rule will be announced in December 2019.

Ms. Medine testified that even if the rule does not change, there are promising methods for complying with the ELG rule that would not require any large capital expenditure by Vectren South. Ms. Medine stated that Vectren South only considered a capital-intensive compliance strategy for ELG compliance at the A.B. Brown station and did not consider other possible options. Ms. Medine identified the possibility of entering into a service contract with a water treatment company and an alternative scrubber retrofit technology as possible compliance options. These options are further discussed by Mr. Difillipo and Ms. Dombrowski, respectively. Ms. Medine cited to Vectren South's response to ICC DR1-4.11 in which Vectren South admitted it has not studied alternative scrubber technologies for A.B. Brown because it does not plan to retrofit the units with a new scrubber. Ms. Medine testified that by limiting consideration of available ELG compliance alternatives, both in the 2016 IRP and the updated modeling for this case, Vectren South is paying attention only to evidence that supports its preferred outcome of building a new CCGT.

Ms. Medine criticized Vectren South's 2016 IRP and Vectren South's failure to properly update its IRP results for this case. Ms. Medine noted that in generating its 2016 IRP, Vectren South assumed for all 15 modeled portfolios the implementation of the Clean Power Plan ("CPP"), implementation of the ELG Rule, and Vectren South's exit from the Warrick #4 station that Vectren

South co-owns with Alcoa. Ms. Medine testified that Vectren South failed to update its 2016 IRP modeling in light of known and likely changes to the CPP and ELG Rule. Ms. Medine pointed out that even with these assumptions, the net present value of revenue requirements ("NPVRR") for Vectren South's preferred portfolio (which included the new CCGT and the early retirement of the A.B. Brown 1 & 2 and Culley 1 stations) was only $60 million (less than 2%) lower than Vectren South's base case, which is within the margin of error of the assumed cost of the CCGT. Ms. Medine testified that if the costs and revenues associated with an assumed CPP are removed, the base case NPVRR is lower than the Vectren South's preferred portfolio.

Ms. Medine quoted the Commission's Final Director's Report for the 2016 Integrated Resource Plans (Director's Report), which acknowledged that changes occurring after a utility submits its IRP, such as the roll-back or review of environmental regulations, changes in administration policies, and newly discovered gas opportunities or technologies, generally do not require changes to an IRP "unless changes are required by the Commission to support a future filing of a Certificate of Need case or other case." (Emphasis added). Ms. Medine noted that the Director's report clarifies: "If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate." (Emphasis added). Based on the comments in the Director's Report, Ms. Medine testified that it would have been appropriate for Vectren South to fully update its 2016 IRP analysis.

Ms. Medine criticized Vectren South's failure to properly update its 2016 IRP modeling for this case. Specifically, Ms. Medine testified that Vectren South's updates to the 2016 IRP did not account for the following: the regulatory status of the CPP; the regulatory status of the ELG Rule; a range in commodity price forecasts; changes to the status of Alcoa's smelter; the lowest cost option for a scrubber retrofit at A.B. Brown; the lowest cost compliance strategies for ELG; changes in costs and availability of renewables and battery storage; the adequacy of Vectren South's choice of a self-build option for a CCGT; or the impact of Vectren South's preferred plan on the local economy.

With respect to the CPP, Ms. Medine testified that on April 3, 2017, the EPA withdrew the Federal Implementation Plan and the Clean Energy Initiative Program. On October 17, 2017, the EPA published its proposal to repeal the CPP in the Federal Register, claiming that the CPP exceeded the EPA's statutory authority. On December 27, 2017, the EPA published a notice of proposed rulemaking in the Federal Register seeking input on CPP replacement options. Ms. Medine testified that the CPP replacement rule listed to be under review by the Office of Management and Budget, and that the EPA is expected to propose a new rule by the end of 2018. Ms. Medine noted that Mr. Hayet included further discussion of Vectren South's consideration of the CPP in the 2016 IRP and that the differences in results with and without the CPP in the modeling are material.

With respect to commodity prices, Ms. Medine testified that in the 2016 IRP, Vectren South was criticized for using single price forecasts even though they were developed in a stochastic manner. Ms. Medine stated that a stochastically-developed forecast cannot replace the need for scenario analysis. Ms. Medine noted that the Director's report echoed her concern, stating: "the Director agrees with the ICC that a higher natural gas price case might have provided useful information." Ms. Medine testified that despite these facts, Vectren South used a single price forecast for this case and did not perform scenario analyses. Ms. Medine presented a graph from the Energy Information Administration showing a wide range of forecasts for natural gas prices through 2050. Ms. Medine pointed out that the impact of gas prices is highly significant to Vectren South's ratepayers, because Vectren South passes its actual fuel costs through rates. She stated that Vectren South's failure to not present the economics of the CCGT under a high gas price scenario masks the risks that ratepayers could incur. Ms. Medine testified that similar issues are present for Vectren South's assumed capacity prices and carbon prices because these are also highly uncertain.

With respect to Alcoa's Warrick operations, Ms. Medine testified that Alcoa had idled the smelters at its Warrick Operations in 2016, which significantly reduced its power consumption. Ms. Medine testified that Vectren South jointly owns Warrick unit #4 with Alcoa. In its 2016 IRP, Vectren South assumed in all modeled cases that Alcoa would not need the power generated by Warrick #4 and that Warrick #4 would be shut down. Vectren South further assumed that it would serve Alcoa's load. Ms. Medine noted that this resulted in a 150 MW capacity shortfall for Vectren South, which it is using to justify the CCGT.

Ms. Medine testified that in 2017, Alcoa reversed its position and announced it would reopen three of the five potlines—two of the potlines are back in operation, and the third is expected by the end of 2018. Ms. Medine testified that based on the restart, Vectren South and Alcoa negotiated a new joint ownership agreement through 2023 and that nothing in the agreement prevents it from being extended beyond 2023. Ms. Medine testified that Vectren South failed to model the possibility that the Warrick #4 unit would continue to operate beyond 2023, thus reducing its capacity shortfall by 150 MW.

With respect to a scrubber retrofit at A.B. Brown, Ms. Medine testified that Vectren South did not consider such a retrofit necessary when it performed its 2016 IRP analysis, but chose to include the retrofit in its update for this case. Ms. Medine testified that Vectren South engaged B&McD to prepare a cost estimate for a wet limestone scrubber but made no effort to ensure that the cost estimate was the lowest cost replacement scrubber option or even an accurate cost estimate. Ms. Medine pointed to the testimony of Ms. Dombrowski who provided details on an ammonia sulfate scrubber alternative.

With respect to Vectren South's choice to self-build the CCGT, Ms. Medine identified several issues with Vectren South's solicitation of bids for a CCGT. Ms. Medine testified that Vectren South engaged B&McD to conduct the solicitation for bids but that it appears Vectren South was involved in many aspects of the solicitation including the design of the RFP, specifically the definition of the size, location, and term. Ms. Medine noted that Vectren South did not submit a bid as part of the RFP process and therefore was not under the same time constraints as the other bidders. Instead, B&McD evaluated the RFP bids on both a quantitative and qualitative basis, then selected the most attractive bids and compared them to the Vectren South bid. Ms. Medine testified that had Vectren South submitted a bid as part of the RFP process, it could have avoided the appearance of a conflict of interest. Ms. Medine pointed to the testimony of Mr. Hayet who identified numerous inconsistencies in B&McD's comparison of the lowest cost option under the RFP to the Vectren South self-build option, perhaps most glaringly, the use of what appears to be an incorrect cost for the Vectren South CCGT.

Ms. Medine noted that B&McD concluded the economics between the lowest bid and Vectren South's self-build option were relatively close, but that Vectren South's self-imposed and unproven belief that a self-build option was less risky swayed the results. Ms. Medine testified that Vectren South provided insufficient evidence to support its claim that a self-build option is less risky than other non-Vectren South-owned options. Ms. Medine pointed to Vectren South's response to this question posed in discovery, which included references to two articles, one involving the growth of renewable generation and one involving difficulties facing merchant power plants. Ms. Medine explained why neither of these article support Vectren South's claim that a self-build option is less risky. Further, Ms. Medine testified that Vectren South and B&McD failed to acknowledge the risks associated with the self-build CCGT option, including: cost over runs; high future natural gas prices; lack of portfolio diversification; inability to take advantage of material advances in renewables and storage; the possibility of high carbon prices, and the possibility of declining demand for electricity.

With respect to the impact on the local economy, Ms. Medine testified that Vectren South considered only the impact of loss of employment as a result of a power plant closing and concluded there would be zero impact. Ms. Medine pointed out that Vectren South's report did not address the loss of in-state coal mining jobs, the loss of coal transportation jobs, the loss of mining equipment maintenance jobs, and the multiplier effect of those losses. Ms. Medine testified that the report also did not address the loss of dollars to the Indiana economy related to the displacement of the sale of Indiana coal by out-of-state natural gas. Ms. Medine noted that the testimony of Ms. Davis estimates the impact on the local economy would be significant.

Ms. Medine testified that Vectren South has a financial incentive to construct the CCGT because it will significantly increase the company's earnings. Ms. Medine provided Confidential Att. ESM-5 to her testimony, which shows Vectren South's forecasted earnings growth assuming the approval of the CCGT. Ms. Medine also testified that Vectren South's request in this case coincides with its pending acquisition by CenterPoint Energy. Ms. Medine stated that CenterPoint has offered Vectren South's shareholders $72 per share of Vectren South Stock, which is a 9.8% premium over the stock's closing price on the day before the announcement. Ms. Medine further stated that CenterPoint agreed to a very attractive severance plan for Vectren South executives. Ms. Medine noted certain elements of the Agreement and Plan of Merger between Vectren South and CenterPoint and certain publicly available documents regarding the merger suggesting that the agreement may be voidable if the CCGT is not approved.

Ms. Medine testified that Vectren South did not address the customer rate impact of its requests in this case. Ms. Medine noted that Mr. Chapman testified that replacing a majority of Vectren South's generation will have a significant rate impact. In addition, Ms. Medine noted that Mr. Swiz further explained that in this case Vectren South is seeking approval of certain accounting treatment related to the CCGT including accruing post-in-service carrying charges, deferral of the accrual of depreciation expenses, and the creation and amortization of a regulatory asset to record the foregoing costs. Ms. Medine testified that without an analysis of the rate impact, the Commission lacks significant information for weighing the impact on ratepayers in making its decision in this case.

Ms. Medine testified about a life cycle analysis ("LCA"), which determines both the upstream and downstream greenhouse gas ("GHG") emissions over the life of a proposed asset. She explained that the upstream portion includes fuel production through its delivery to the consumer and the downstream portion includes the operation of the power plant.

Ms. Medine prepared an LCA comparing the new CCGT to a reasonable future generation mix if the coal plants are not prematurely closed. Ms. Medine assumed that Vectren South's existing coal plants would be replaced with wind generation, but she testified that the same analysis would apply if coal were replaced by solar, energy efficiency, etc. Ms. Medine conducted her analysis over a 40-year expected lifetime of the new CCGT. She provided this analysis in Att. ESM-8.

Ms. Medine's analysis shows that the lifetime GHG emissions are 46 percent lower without the new CCGT. Ms. Medine testified that other parties have voiced similar concerns, for example the Rocky Mountain Institute ("RMI"), which published a report arguing that specific clean energy portfolios already outcompete proposed gas-fired generation and that new investments in gas plants and pipelines risk becoming stranded assets. The RMI report recommends that "regulators should carefully consider alternatives to new gas power plant construction before allowing recovery of costs in rates."

Ms. Medine provided her initial comments on the Commission's draft statewide analysis. She testified that the draft analysis is largely a compilation of information taken from pre-existing report prepared by other entities, including the IRPs filed by Indiana public utilities from 2015 through 2017, the State Utility Forecasting Group's December 2017 forecast, the Energy Information Administration's 2018 Annual Energy Outlook, and selected information published by MISO and PJM. Ms. Medine pointed out significant differences in the assumptions underlying these reports, for example, whether the reports assume a carbon regime, differing outlooks regarding future electricity demand growth, and the use of stale data. Ms. Medine noted that the draft statewide analysis in not consistent with comments in the Commission's 2016 IRP Director's Report, which provided significant insight into the increasing complexity of the utility market, which is not reflected in the draft statewide analysis.

b. Philip Hayet, Mr. Hayet testified on behalf of the ICC. He is a utility regulatory consultant and the Vice President of J. Kennedy and Associates, Inc. In his work, Mr. Hayet makes extensive use of the ABB Strategist modeling software employed by Vectren South in this case. Mr. Hayet also previously worked for the company that developed the Strategist software and provided training and support in its use. His testimony challenged the economic analyses performed by Vectren South to provide the basis for its CPCN petition in this Cause. Mr. Hayet also performed an independent modeling analysis using Strategist and presented his results.

Mr. Hayet identified several errors and inconsistencies in Vectren South's modeling and identified important factors that were not taken into consideration. Specifically, he determined that Vectren South neglected to rely on the most recent information available including revisions to the tax law, reduced regulatory requirements related to CO_2 and the most up-to-date cost information for the CCGT facility. Mr. Hayet concluded that it would be in the ratepayers' best interest to delay the decision to build the CCGT to allow time to explore other resource options and to gain greater clarity about pending environmental regulations.

Mr. Hayet testified that the primary planning exercise performed by Vectren South that led to its decision to retire 730 MW of coal-fired capacity and construct a CCGT occurred during its 2016 IRP Process. For purposes of this case, Vectren South performed an updated, but abbreviated, IRP analysis. Mr. Hayet stated that the updated analysis for this case considered far too few scenarios considering the significant factors that have changed since the 2016 IRP was performed.

Mr. Hayet noted that Mr. Chapman testified that Vectren South preferred to seek a diversified generation portfolio and did not merely choose the plan with the lowest NPV. Mr. Hayet pointed out, however, that Vectren South is actually recommending a portfolio that merely changes its system from being dominated by four coal-fired generation units to being dominated by a single natural gas-fired generation facility, which will lead to its system being less diverse. Based on this, Mr. Hayet encouraged the Commission to completely discount Vectren South's argument concerning diversity as a basis for approving the CCGT construction. Mr. Hayet presented other possible portfolios that could meet Vectren South's objectives for diversity at a lower cost.

Mr. Hayet challenged Vectren South's updated IRP modeling for this case. Specifically, he stated that Vectren South neglected to account for significant factors that have occurred since the 2016 IRP analysis, including significant tax reform legislation and the Trump Administration's efforts to repeal the Clean Power Plan and to modify the ELG rule and other environmental regulations. He stated that Vectren South also used the same CO_2 costs, the same assumed date for CO_2 costs to begin, and the same Clean Power Plan assumption that allowances would be traded, despite recent events that could have a material impact on those assumptions, for example, the withdrawal of the Federal Implementation Plan and the proposed repeal of the Clean Power Plan.

Next, Mr. Hayet challenged Vectren South's RFP process, which was performed by B&McD. Vectren South received 11 proposals from six different developers. After ranking the proposals, B&McD identified a single finalist company. Only then, did B&McD compare the finalist to Vectren South's self-build option. Mr. Hayet stated that it was highly unusual that Vectren South did not submit its self-build proposal into the RFP at the beginning, but rather compared it only to other bids in the final selection process. Further, Mr. Hayet noted that Vectren South's analysis only compared four CCGT alternatives (two self-build options and two bids) to each other rather than determining the best long-term resource plan for Vectren South's customers. Mr. Hayet also demonstrated that the bid evaluation process used inconsistent capacity and capital assumptions in different calculations. For example, Mr. Hayet showed how with respect to one bid, the analysis used three different capacity values. He recommended that Vectren South perform a thorough review of all input assumptions to ensure that proper and consistent assumptions were modeled, and he recommended that an updated IRP analysis be performed to ensure that the best long-term resource plan has been selected for Vectren South's customers.

Mr. Hayet performed his own modeling analyses using the Strategist model. Specifically, he conducted an analysis of a reasonable alternative to Vectren South's preferred plan with a number of corrections that he believed were necessary. Mr. Hayet modeled a scenario where Vectren South deferred the decision to add a new CCGT unit in 2024 and continued to operate the Brown 2 unit for a longer period. Mr. Hayet assumed that the Brown 1 and 2 units would operate to the end of their scrubbers' useful lives based on a recent Condition Assessment Report performed by B&McD. He compared this scenario to Vectren South's preferred CCGT case and Vectren South's alternative scenario where the Brown 1 and 2 units continue to operate with new scrubbers installed. Mr. Hayet removed the CO_2 revenue assumptions, assumed the market could supply up to 250 MW of Vectren South's capacity needs through 2030 at a price of 75% of the cost of new entry, adjusted the maximum reserve margin from 35% to 36%, and lowered the federal corporate tax rate from 35% to 21%, among other changes. Perhaps most importantly, Mr. Hayet corrected Vectren South's cost assumption for the self-build CCGT to the most up-to-date amount of $781 million, which Vectren South did not use in any of its economic evaluations, including the updated Strategist modeling for this case. Mr. Hayet also performed a second modeling analysis using Strategist, in which he continued to operate the Brown 2 unit for a longer period and then, instead of adding a new CCGT, added additional smaller renewable resources. This model proved similarly economic, while increasing Vectren South's flexibility and diversity.

Based on his results, Mr. Hayet showed that these delay cases were either less expensive or comparable to Vectren South's preferred CCGT option. Further, Mr. Hayet testified that these delay cases provide Vectren South a greater degree of flexibility to consider other alternatives in the future, including the possibility of adding more renewable resources. Mr. Hayet asserted that Vectren South had not justified its $1 billion plus request in this case. He recommended that the Commission reject Vectren South's proposal to retire 730 MW of coal-fired capacity and add an 850 MW CCGT by 2024. He stated that Vectren South should conduct a robust analysis of its options and costs, and if it determines the resource is still needed, refile its petition.

c. **Charles D. McConnell**. Mr. McConnell testified on behalf of the ICC. Mr. McConnell is the Executive Director of Rice University's Energy and Environment Initiative. Mr. McConnell testified about the impact of emerging policies addressing electricity grid resilience on Vectren South's preferred generation portfolio.

Mr. McConnell began by explaining the difference between resilience and reliability, which although related are critically different. He testified that the North American Reliability Corporation ("NERC") defines reliability of the interconnected bulk power system ("BPS") in terms of two basic and functional aspects: adequacy—or the ability of the electric system to supply the electric power and energy requirements of consumers at all times; and reliability—or the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.

Mr. McConnell testified that NERC has not formally defined resilience, but has proposed to largely adopt the definition developed by the National Infrastructure Advisory Council, which is: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." He noted that PJM defined resilience as "preparing for, operating through, and recovering from a high-impact, low-frequency event."

Mr. McConnell testified that for decades, the U.S. could depend on fuel-secure coal-fired electric generation, with a fleet-wide average of 71-104 days on on-site fuel reserves in 2017. He claimed that, with on-site fuel and generally stable supply chains, these coal-fired facilities could be expected to generate in all but the most unlikely of circumstances. He opined that this presence of significant fuel-secure electric generating capacity aligned grid reliability and resilience at the generation level, which allowed planners to confine resilience concerns to ensuring that transmission and distribution systems could withstand disruption, *e.g.* from storm damage.

Mr. McConnell testified that changes in the electric grid, particularly related to generation, have highlighted the difference between resilience and reliability. He observed that the U.S. coal fleet is retiring at historic rates across the country, with almost 40% of the U.S. coal fleet having retired or announced plans to retire since 2010. He claimed these facilities (93,000 MW by 2020) are being replaced by natural gas and renewable generation, which lack the fuel security necessary for resilience. Vectren South's preferred portfolio follows this trend, reducing coal-fired generation and replacing it with natural gas-fired generation. Mr. McConnell testified that this leads to risks arising from low ratios of fuel-secure electric generating capacity. He stated that recent PJM studies like the Black Sky/Black Start Protection Initiative suggest that 30 days of fuel inventory would be required to a Black Sky event—defined as a catastrophic event that severely disrupts the normal functioning of critical infrastructures in multiple regions for long durations. Mr. McConnell explained efforts undertaken by the Federal Energy Regulatory Commission ("FERC") and other regional system operators to address resilience. For example, FERC recently initiated a rulemaking to specifically evaluate the resilience of the BPS in the regions operated by independent system operators and regional transmission operators.

Mr. McConnell stated that Vectren South's preferred portfolio does not align with policies under consideration to address grid resilience or its own IRP statement that "flexibility is another important objective for Vectren South's future portfolio." Instead, Mr. McConnell testified, Vectren South's preferred portfolio increases dependence on natural gas and retires fuel-secure coal-fired generating facilities. He pointed out that using the Vectren South IRP's measurement of flexibility, the preferred portfolio would substantially reduce Vectren South's agility to react in a timely manner to policies addressing resilience.

Mr. McConnell recommended that Vectren South delay implementation of its preferred portfolio to provide time to better understand the impact of grid resilience policies. He stated that this would allow Vectren South to leverage tools now under contemplation to assess new generation resilience concerns and to plan to mitigate risk to gas infrastructure of extreme weather, physical attacks, and cyber-attacks.

iv. Intervenors Citizens Action Coalition of Indiana, Sierra Club, and Valley Watch

a. Kerwin Olson, Executive Director of Citizens Action Coalition, testified on behalf of Citizens Action Coalition, Valley Watch, and Sierra Club.

Mr. Olson pointed out how Vectren South has imposed the highest monthly bills in the State for a customer using 1,000 kWh per month since 2011. All parties agreed that "Vectren South does have the highest residential electric rates in Indiana." Pet. Ex. 1-R, p. 27. On average, Mr. Olson showed that Vectren South customers pay $21 more per month than residential customers of Northern Indiana Public Service Company ("NIPSCO"). He noted how Vectren South customers' average monthly bill is about $40 more than the Indiana average, and $60 more than the average Illinois bill. He explained that Vectren South's average price per kWh is the highest of any Indiana investor-owned utility. Mr. Olson further showed how Evansville and Vanderburgh County have higher poverty levels and lower income levels than Indiana as a whole and how high Vectren South bills exacerbate these problems. Mr. Olson urged the Commission to deny Vectren South's request in this proceeding, to prevent further suffering by Vectren South's captive customers.

Mr. Olson provided a chart showing that Vectren South's average bill for a customer using 1,000 kWh per month, already the highest in Indiana in 2005, skyrocketed 73% between 2005 and 2011. Mr. Olson's chart showed that these rates stayed far above all other Indiana utilities through 2017. Vectren South conceded that Mr. Olson's chart displaying this increase "accurately reflects the history of Vectren South's residential rates." Pet. Ex. 1-R, p. 27.

Mr. Olson pointed out that the testimony of Vectren Witness Swiz detailed Mr. Swiz's concern for Vectren South's shareholders, rather than its customers. Mr. Olson explained his understanding that Vectren South seeks to minimize its exposure to any risk related to earnings. Mr. Olson explained that Citizens Action Coalition would support investment of ratepayer dollars where risk is appropriately shared between ratepayers and shareholders and where the effect of rate increases is appropriately considered.

Vectren South conducted a field hearing in this proceeding. Mr. Olson, a veteran of numerous field hearings, called this one of the longest and most intriguing he had ever attended. He explained how thirty-seven people across the cultural and political spectrum spoke out against the methane gas plant and accompanying rate hikes, with only four people in favor. He highlighted how the Evansville Courier & Press succinctly described the field hearing: "Who opposed Vectren South's proposed natural gas plant and rate hikes at Wednesday's public hearing? Almost everybody." Mr. Olson urged the Commission to review the field hearing transcripts, as they reflect the voices of the ratepaying public. Mr. Olson noted that the ratepaying public's interests are equal to, and must be balanced with, the interests of the utility, large customers, and intervenors.

Mr. Olson explained that CAC committed significant time and resources to the Vectren 2016 IRP process: attending all meetings, serving informal discovery, analyzing the modeling files, and submitting extensive comments on Vectren South's 2016 IRP and the Director's draft Report on the 2016 IRPs. He testified that Vectren South's commitment, by contrast, was lacking: Vectren South failed to submit an updated 2016 IRP, despite numerous comments urging updates, and plenty of time to submit that update. Mr. Olson found Vectren South's lack of effort in the 2016 IRP Stakeholder process "disappointing, to say the least."

b. Tyler Comings, Senior Researcher at Applied Economics Clinic, testified on behalf of Citizens Action Coalition, Valley Watch, and Sierra Club. Mr. Comings criticized Vectren South's modeling methodology, certain modeling inputs, risk analysis, and request for proposals. In sum, Mr. Comings recommended denial upon finding the Vectren South's proposal inadequately supported and excessively risky for ratepayers.

Mr. Comings opined that Vectren South's modeling process was too convoluted to yield a sufficiently transparent or credible result. Mr. Comings explained that the more models (and iterations of modeling) used, the more difficult it is for the Commission and stakeholders to follow the Company's process. Mr. Comings observed that the use of so many models in the actual selection of a preferred portfolio creates ample opportunity for flawed and/or inconsistent input assumptions and other settings creating bias in favor of the preferred build. Further, Mr. Comings noted that even setting aside the problems with Vectren South's methodological approach, its preferred portfolio is neither least-cost nor least-risk based on its own analysis. He complained that Vectren South does not explain how it weighed cost versus risk in its final decision making, specifically noting that the risk analysis relied upon cannot resolve the issue because that analysis exclusively relied on 2016 IRP inputs and never incorporated the updates on which the final decision was based. Mr. Comings further criticized Vectren South's post-IRP modeling approach for not re-evaluating the coal retirement decisions in light of the availability of more up-to-date assumptions for several inputs. He explained that Vectren South instead hard-wired coal retirement decisions in the updated Strategist modeling.

Mr. Comings noted that Vectren South's preferred plan is neither least-cost nor least-risk according to the Company's analyses. He explained that the preferred plan was not the lowest cost option and was very close in cost to several alternatives in the Strategist modeling for the 2016 IRP. He continued to explain that the preferred plan was ranked 9th out of 15 portfolios for cost in the Aurora modeling. He observed that the preferred plan was neither least-cost nor least-risk in Pace Global's evaluation of "cost-risk trade-off" for the 15 portfolios either, and that Pace Global's analysis concluded with the preferred portfolio ranked third. He further testified that, rather than modeling a diverse set of resources, Vectren South instead focused on different types of gas procurement through portfolios that were very similar to each other, with 9 of 11 including a new gas combined cycle generator. Ultimately, Mr. Comings concluded that Vectren South seeks to procure a larger gas plant than it needs when even its own modeling shows that a smaller plant would cost ratepayers less.

Mr. Comings testified that Vectren South rejects portfolios that offered lower cost and lower risk for insufficient reason. He explained that Vectren South rejected "Portfolio D" claiming (1) the likelihood of a "significant capacity deficit," (2) uncertainty with regard to future capacity credit for wind in MISO, and (3) that keeping Culley 3 online would provide "additional flexibility to meet future growth." In response, Mr. Comings noted that Portfolio D included an average capacity purchase of 35 MW per year, just 12 MW higher than Portfolio L's 23 MW of annual purchases—an increase of less than one percent of Vectren South's capacity. Moreover, Mr. Comings observed that the risk analysis—which concluded Portfolio D presented less risk than Vectren South's preferred portfolio—already accounted for capacity purchase risks. He testified that Vectren South counted capacity risk twice by including it as a factor in the risk analysis and then again using the factor to reject a better-performing portfolio. Next, Mr. Comings opined that any alleged uncertainty over wind capacity credits is not a reason not to pursue additional wind resources. Like myriad other uncertain elements in electric system modeling, Vectren South could have estimated future credits. Finally, Mr. Comings noted that the risk analysis had purportedly already accounted for "balance" and "flexibility" when in concluded that Portfolio D was less risky than Portfolio L. As a result, Mr. Comings opined that Vectren South's claim that Culley 3 was needed for "flexibility" again relies on a factor already claimed to be accounted for in the risk analysis. Ultimately, Mr. Comings explained that while the modeling exercises were meant to justify Vectren South's plan, the ultimate resource investment decisions were based on subjective, qualitative factors that had the effect of overriding modeling results showing lower cost, lower risk alternatives.

Mr. Comings disagreed with Vectren South claims that its preferred portfolio amounts to a "diversification strategy." Mr. Comings testified that Vectren South's plan is simply one that replaces a heavy reliance on coal with a heavy reliance on gas. He cautioned that relying so heavily on a single plant for energy and capacity creates significant risk. By way of example, he observed that most of Vectren South's energy would need to be purchased from the wholesale market if that one plant were on either a forced or planned outage. In sum, Mr. Comings testified that what Vectren South proposes is not a diversification at all, but a radical swing from overreliance on one fuel to overreliance on another.

Beyond modeling methodology, Mr. Comings' testimony continued to inventory major flaws and inconsistencies in Vectren South's analysis. According to Mr. Comings, these flaws included: (1) mischaracterization of market risk and introducing market risk exposure; (2) overestimation of load; (3) underestimation of demand response; (4) overestimation of renewable resource costs; (5) use of a biased and arbitrary risk scoring system; and (6) a failure to encourage other resource options in the request for proposals. Taking each in turn, Mr. Comings testified that Vectren South took a one-sided view of market risk, concluding that having surplus capacity and generation only offers benefits to ratepayers—a view that only hold true if market prices and/or load are high. He observed that, under today's capacity market conditions, excess capacity would be sold at very low market prices. In contrast, he noted that Vectren South overestimated future capacity prices in its modeling, as it has consistently done in previous modeling. Mr. Comings explained that this overestimation of capacity prices is important because it makes the economics of building a new resource more attractive, biasing the modeling towards portfolios that oversupply Vectren South's capacity need.

He continued to explain that Vectren South's plan introduces market risk exposure by significantly overbuilding capacity: if the proposed gas plant is built, Vectren South would have 22% more capacity than what it needs to maintain a planning reserve margin above its peak load, with a sizeable surplus remaining through 2036. Mr. Comings explained that Vectren South is focused on the possibility of high load and high market prices to justify its plan, but the excess capacity it seeks could cost ratepayers more when market prices are not sufficiently high or if load is not as high as Vectren South expects. Mr. Comings testified that Vectren South's analysis assumes it will generate more electricity than it has in the past and that it will be able to bring in additional revenue by selling excess generation. He observed that the forecast for 2017 generation overstated Vectren South's actual production. He opined that, by assuming significantly more generation, the modeling was biased toward portfolios that oversupply the system. He testified that the portfolio NPVs show significant off-system sales revenues, and cautioned that ratepayers would bear much of the risk that these sales will not materialize. Mr. Comings opined that had Vectren South presented more realistic modeling, its preferred plan would have appeared significantly more expensive.

With respect to the load forecast, Mr. Comings testified that Vectren South relied on a load forecast supplied by Itron for the 2016 IRP modeling.

He explained that the forecast included an assumption that Vectren South would serve an unspecified level of new industrial load. He compared that forecast to load forecasts Vectren South provided to MISO in 2017 and 2018, and he found that the Itron forecast notably exceeds both MISO forecasts.

With respect to demand response, Mr. Comings observed that Vectren South is among the lowest performing of Indiana's investor-owned utilities in terms of demand response as a percentage of peak load. He referred to a report prepared for Indiana Advanced Energy Economy which found "Vectren . . . show[s] limited contribution to resource adequacy from C&I [commercial and industrial] demand response" and indicated Vectren South had unrealized demand response potential. Mr. Comings compared Vectren South's current payment credits under its demand response tariffs to other Indiana utilities, which offer greater incentives and utilize higher percentages of demand response.

With respect to renewable energy, Mr. Comings testified the Vectren South overestimated capital and O&M costs. For wind resources, Mr. Comings concluded that Vectren South used higher capital costs and lower O&M costs than he would recommend. For wind capital costs, Mr. Comings opined that Vectren South should have used National Renewable Energy Laboratory's Annual Technology Baseline ("NREL ATB") Techno-resource group 6. For solar resources, Mr. Comings concluded that Vectren South used higher capital and O&M costs than he would recommend. Mr. Comings suggested Vectren South should have used the ATB midpoint projections for utility-scale PV with a 20% capacity factor. Mr. Comings explained that the effect of using higher cost assumptions was an overestimation biasing the modeling results against renewable resources.

Mr. Comings offered several critiques of Pace Global's risk analysis. Mr. Comings commented that the analysis used arbitrary thresholds to evaluate certain risks and arbitrarily weights risk factors. As mentioned above, the "capacity purchase" metric took a one-sided view of risk, and Mr. Comings opined that it should also have accounted for the risks of excess capacity. Mr. Comings observed that the "market purchases" metric is similarly one-sided. While expressing agreement with the decision to remove "remote generation" and "net sales" metrics per recommendations in the IURC Director's 2016 IRP Report, Mr. Comings opined that Pace Global should have also re-run the risk analysis modeling with updated inputs. He observed that Vectren South arbitrarily weighted all metrics equally in the risk analysis, without providing any explanation of why each factor should carry equal importance.

Mr. Comings noted that he was unable to fully vet Vectren South's comparison of resource alternatives. At the time of his testimony, Vectren South had not provided requested documentation to allow verification that the capital costs of the new pipeline were accurately accounted for in the modeling. Mr.

Comings expressed further concern related to the pipeline over potential cross-subsidization between Vectren South's gas and electric customers.

Mr. Comings testified that, beyond problems with the modeling, Vectren South did not facilitate a competitive bidding process to aid its resource selection. He explained that Vectren South instead issued an RFP that sought only gas resources offering 600-800 MW, expressed a bias in favor of ownership over purchased power agreements ("PPAs"), required any PPAs to have at least 20-year terms, and required siting in Zone 6. He explained that these requirements excluded potentially lower-cost and diverse alternatives. He contrasted Vectren South's RFP with NIPSCO's recent all-source RFP, which received considerably more bids and provided specific wind and solar project prices.

Ultimately, Mr. Comings recommended denial of Vectren South's application. Should the Commission grant the requested CPCNs, Mr. Comings recommended conditional approval that: (1) limits capital costs charged to rate payers for the gas plant to the costs presented in this proceeding; (2) applies credits to ratepayers for off-system sales revenue that were projected in this filing but do not materialize; and (3) exempts ratepayers from Culley Unit 3 environmental compliance costs over and above what was included in this filing. Mr. Comings testified that such conditions are necessary to protect ratepayers from the excessive market risk involved in Vectren South's preferred build.

c. **Dan Mellinger**, Senior Consultant at Energy Futures Group, testified on behalf of Citizens Action Coalition, Valley Watch, and Sierra Club. Mr. Mellinger has more than a decade of expertise on energy efficiency issues and has sponsored expert testimony in utility proceedings in Michigan and Minnesota. Mr. Mellinger earned a B.S. in Energy Efficiency from Michigan State University in 1999. Mr. Mellinger explained how he is a licensed professional engineer in Vermont, is Lighting Certified by the National Council on Qualifications for the Lighting Professions, and is a Certified Energy Manager by the Association of Energy Engineers.

Mr. Mellinger criticized three parts of Vectren South's energy efficiency plans. First, Mr. Mellinger explained that Vectren South's estimate of the cost of energy efficiency was too high. Next, Mr. Mellinger explained that Vectren South failed to leverage numerous energy efficiency savings opportunities that could save up to 44,000 gross MWh annually, in addition to Vectren South's planned total of about 37,000 gross MWh saved. Finally, Mr. Mellinger detailed numerous shortcomings of Vectren South's Market Potential Study ("MPS") for energy efficiency. Mr. Mellinger recommended that Vectren South's request in this proceeding be denied until the company drastically increased its energy efficiency investments.

Overall, Mr. Mellinger explained that for each year from 2018 through 2036, Vectren South estimated the cost of energy efficiency separately for each of eight different "blocks" of energy efficiency, each block representing gross savings equal to 0.25% of eligible sales. He summarized the four-step approach Vectren South took to estimating the cost of energy efficiency for the 2016 IRP, and explained that Vectren South used a number of incorrect assumptions. Mr. Mellinger provided a revised table of the cost of each block of energy efficiency, correcting these errors. Mr. Mellinger's table demonstrated far lower costs than the costs Vectren South presents in this proceeding.

For Block 1 in the IRP model, Vectren South made four errors in estimating the cost for energy efficiency, which resulted in overestimating the cost of Block 1 by about 28%. One such error was Vectren South's use of 2016 planned cost figures, rather than using the available 2016 actual (evaluated) results or the 2017 actual (evaluated) results. The best starting point was 2017 actual results. Instead, Vectren South used the worst starting point: the 2016 planning assumptions. JI Ex. 3, p. 7. Adjusting for inflation, 2016 planning assumptions were about fifteen percent higher than 2017 actual results: this is a significant overage. The next error in the Block 1 cost development according to Mr. Mellinger was Vectren South's assumption that 2016 planning costs were in 2015 dollars, inappropriately escalating the cost by one year of inflation. Vectren South conceded this was an error: "Mr. Mellinger is correct, that the 2016 costs should not have been adjusted by the 1.6% inflation rate." Pet. Ex. 8-R, p. 7, ll. 7-12. Mr. Mellinger's third error that he identified in Vectren South's Block 1 cost development was Vectren South's mismatch of 2016 planned costs to just one block of savings, when the 2016 planned costs covered 5.2 blocks of savings.

The final error in the Block 1 cost development according to Mr. Mellinger was Vectren South's use of a net-to-gross ratio of 0.8, when it should have used 0.83 (from the 2015 evaluation) or 0.84 (the average net-to-gross ratio from 2012-2017). Because Vectren South developed its cost estimate for gross savings, it had to apply a net-to-gross ratio. Vectren South assumed a net-to-gross ratio "based on the latest available evaluation at the time of the analysis, which was the 2015 evaluation." Pet. Ex. 8-R, pp. 5, ll. 2-3. Vectren South's 2015 evaluation results "indicated an 83% [net-to-gross ratio] for the entire portfolio." Pet. Ex. 8-R, p. 6, ll. 3-4. Instead of using the actual net-to-gross ratio, Vectren South simply rounded 0.83 down to 0.80. Mr. Mellinger asserted that this created a rounding error, removing accuracy from Vectren South's cost of energy efficiency without any justification for this practice. Mr. Mellinger also pointed out that the 0.80 figure used for Vectren South's estimated cost of energy efficiency also conflicts with Vectren South's average net-to-gross ratio for 2012-2017, which was 0.84.

After identifying the errors in Vectren South's development of Block 1 energy efficiency costs, Mr. Mellinger identified that Vectren South assumed that the real (inflation-adjusted) cost of energy efficiency savings will increase by 4% annually. Mr. Mellinger contended that Vectren South provides no strong evidence "that the real (inflation-adjusted) cost of savings is increasing at all." Mr. Mellinger noted that Vectren South's 4% figure was not derived from its own empirical data, rather Vectren South continued to rely on Dr. Stevie's report that was criticized by the Director's 2016 IRP Report. Mr. Mellinger pointed out that the Director's Report from the 2016 Integrated Resource Plan criticized Vectren South for using these unsupported assumptions, instead of "empirical data derived from DSM effects by Vectren South's customers." Mr. Mellinger showed that the empirical data derived from DSM effects on Vectren South's customers from 2013 through 2017 shows an actual Compound Annual Growth Rate of 0.4% per gross kWh. JI Ex. 3, p. 10.

Finally, Mr. Mellinger testified that Vectren South incorrectly used pre-tax weighted average cost of capital to levelize efficiency costs. He pointed out that supply-side options other than energy efficiency are capitalized with a rate of return for shareholders, while energy efficiency programs are not. By levelizing the cost of energy efficiency with the pre-tax weighted average cost of capital, Vectren South has effectively treated energy efficiency in the same way as these other supply-side options. Mr. Mellinger explained that this is incorrect.

The next major item to which Mr. Mellinger testified was the level of potential savings available to Vectren South. Mr. Mellinger noted that Vectren South maps out just 1% of eligible retail sales through 2020 (37,000 gross MWh), 0.75% of eligible sales through 2027, and 0.5% of eligible sales through 2036. JI, Ex. 3, p. 14. Mr. Mellinger argued that these energy efficiency goals are far too low, pointing out that Commonwealth Edison plans to save 1.98% annually through 2022, while Consumers Energy plans to save 1.45% through 2021, then increase to 2% by 2021 and 2.25% through 2030. Mr. Mellinger detailed five additional energy efficiency programs that could save Vectren South up to an additional 44,000 gross MWh annually. Vectren South conceded the viability of the programs proposed by Mr. Mellinger: "I think **all** of Mr. Mellinger's suggestions can be considered as part of Vectren South's ongoing [Market Potential Study] analysis and [Energy Efficiency] Planning process." Pet. Ex. 8-R, p. 11 (emphasis added). Vectren South conceded that, for this filing, it had only vetted some, but not all, of the programs offered by Mr. Mellinger: "All of the programs offered by Mr. Mellinger have previously been vetted **and/or** will continue to be discussed..." Pet. Ex. 8-R, p. 9 (emphasis added).

The additional programs that Mr. Mellinger excluded all industrial customers that opted out of Vectren South's energy efficiency program in 2014 or 2015. Mr. Mellinger proposed Vectren South include a Strategic Energy Management program, which could save as much as 12,000 MWh annually. Mr. Mellinger explained that this continuous improvement approach creates persistent energy and cost savings for industrial and other large customers. He noted that a 2015 evaluation of 128 industrial sites demonstrated an average first year of annualized program savings. Mr. Mellinger next proposed Vectren South include midstream program designs, wherein incentives are applied at the point of purchase for energy efficiency products, significantly increasing market penetration of these products. The third set of efficiency opportunities Mr. Mellinger proposed involved commercial lighting. Mr. Mellinger predicted that Vectren South could save an additional 19,000 MWh annually through promotion of LED lamps and fixtures and networked lighting controls. He explained that the Department of Energy ranks LED fixtures paired with networked lighting controls as the top lighting savings opportunity across all sectors. All parties agreed that commercial lighting projects are very cost-effective. Pet. Ex. 8-R, p. 4. All parties further agreed that "commercial lighting projects help make the ... overall portfolio cost effective and drive down overall costs..." *Id.* Mr. Mellinger noted that Vectren South forecasts a low level of savings from LED lamps/fixtures actually declining over time, but this conflicts with industry trends showing that the technology will be adopted rapidly over the next decade, with savings potential to increase considerably. He also explained how Vectren South's MPS failed to consider LED highbay fixtures or commercial networked lighting controls. Mr. Mellinger also suggested efficiency opportunity in commercial heating at an additional 4,000 MWh annually through a midstream commercial HVAC/refrigeration program, as well as residential HVAC and domestic hot water programs providing up to 9,000 MWh annually through a midstream program. Mr. Mellinger provided his analysis of other missing programs from Vectren South's services, like the promotion of heat pump water heaters to commercial customers, midstream program designs for agriculture equipment and commercial kitchen equipment, promotion of residential connected home devices, and combined heat and power.

Mr. Mellinger criticized Vectren South's overreliance on a MPS to estimate the savings achievable through energy efficiency, and describes several limitations of such studies. He testified that MPSs are inherently conservative and consistently underestimate the amount of achievable savings. He provided evidence that Massachusetts, Rhode Island, and Vermont achieved more than 0.77% more savings than what even the most optimistic study thought possible. He explained that MPSs can only focus on measures that are known and documentable today, but said this was limiting because new efficiency technology is constantly emerging. He noted how Vectren South's MPS even failed to account for emerging technologies. He stated that the studies also fail to capture savings potential from custom measures, unique to specific industries, sites or facilities; fail to account for the fact that for many energy efficiency programs, savings increase and costs decrease over time; fail to include all efficiency benefits; fail to account for market transforming effects; fail to anticipate and forecast new and more effective ways or reaching energy markets (such as how Vectren fails to capture opportunities through midstream programs); use overly simplistic and conservative assumptions about market penetration; and place artificial and arbitrary limits on the size of financial incentives or budgets.

Overall, Mr. Mellinger concluded that Vectren South's cost estimates were too high and its assumption about achievable levels of energy efficiency savings were too low. He provided his expert opinion and analysis that energy efficiency has the potential to play a much bigger role as a cost-effective resource within Vectren South's territory. He recommended Vectren South's request be denied at least until it drastically increases its energy efficiency investments.

v. **Intervenor Sunrise Coal**

a. **Alison F. Davis**, Professor of Economics at the University of Kentucky and Executive Director of the Community and Economic Development Initiative of Kentucky, presented the results of her study concerning the negative economic impact of Vectren South's plan to retire most of its coal fired generating units and construct a CCGT. Professor Davis' study found that if the coal-fired plants Vectren proposes to close were taken out of service at the end of 2023, it would represent a 10% reduction in coal production and sales in Knox County and the surrounding region. That would result in a significant loss to the regional economy. In total her study estimated a loss of 186 jobs and the total negative economic impact to be approximately $498 Million through 2036. That impact did not include the loss of jobs from converting from the coal-fired plants to a gas-combustion plant. In addition, she testified that Vectren South's coal-fired plants use local coal but the proposed CCGT would import gas from out-of-state, sending dollars that were once circulating locally in the economy to another state.

b. **Katherine Dombrowski**, process chemical engineer at Trimeric Corporation, presented her testimony and report on her investigation of the alternative of retrofitting A.B. Brown 1 & 2 with an ammonia-based SO_2 scrubber technology that could eliminate or materially reduce the wastewater discharge from the scrubbing process and produce commercially saleable agricultural fertilizer as a byproduct.

c. **Michael N. DiFilippo**, DiFilippo Consulting, testified concerning his analysis of the feasibility of certain wastewater treatment options such as those offered by Purestream Services and Heartland Water Technologies for use at Vectren South's A.B. Brown Generating Station on a temporary basis, in order to meet the present final ELG regulations of the EPS. Mr. DiFilippo testified that these two technology service providers provide portable (as well as permanent) equipment to treat high salinity wastewater, and in advance of the ELG guidelines, both companies had been evaluated (by means of pilot testing) by the Electric Power Research Institute ("EPRI") and independently by some electric utilities to treat scrubber and ash pond leachate coal plant wastewater.

vi. Intervenor Industrial Group

a. **Michael P. Gorman**, Managing Principal of Brubaker & Associates, Inc., testified concerning his recommendations for certain adjustment or conditions to be placed on any CPCN issued in this case. Mr. Gorman opined that the Company's proposal to develop and place in-service a new CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases costs for new generation resources and retains material costs for retired generating services that will become unrecovered stranded costs. He recommends mitigation measures to reduce the cost burden on customers due to these generating resource cost impacts by taking measures to mitigate stranded cost recovery and mitigate the initial cost to customers for the cost of a new CCGT. He proposed certain commitments and guarantees that Vectren South should undertake in order to protect customers from excess cost overruns of developing a new CCGT. Mr. Gorman also proposed protections to customers that a new CCGT must meet the anticipated operating performances that are relied on as support for the CCGT as an economic resource. He also expressed concerns about the Vectren South's proposal for a self-build gas lateral to deliver gas to the CCGT, characterizing it as possibly anti-competitive, with the potential to increase the CCGT resource cost to retail customers. He also commented on appropriate cost recovery of the CCGT gas lateral cost. He recommended to 100% of off-system sales revenues be credited to customers.

C. Rebuttal Evidence

i. Vectren South

a. **Carl L. Chapman** testified in response to a number of issues raised by the parties opposing Vectren South's resource plan. He stated that (1) the proposal to build a CCGT to provide baseload capacity is based on sound analysis, and is not an improperly motivated scheme; (2) the CCGT unit is properly sized to replace retiring baseload coal capacity and to also replace older peaker units with very low cost peaking capacity; (3) the partnership with ALCOA to jointly operate Warrick 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option; (4) speculation regarding short-term federal subsidization of coal units does not change the operational challenges facing the Brown units that dictate their retirement; (5) Illinois Basin coal production is stable and the retirement of Vectren South's small units (with the retention of its best coal unit) is unlikely to materially harm future production; (6) reliance on merchant plant developers and PPAs inherently presents more risk to long-term resource reliability compared to a regulated utility project; and (7) Vectren South's rates will have been close to flat for 14 years through 2024 and the preferred resource plan is the best long-term option in terms of risk and cost.

b. Wayne D. Games testified that continuing to operate the A.B. Brown coal units beyond 2024 poses significant risks. He said those units face competitive challenges in the Midcontinent Independent System Operator energy market. He also explained why Vectren South contends that the CCGT it proposes presents lower risks. He also discussed issues with converting the Brown units from coal to gas fired, and the project timeline and risks associated with delaying until the next IRP. He explained why Vectren South's preferred plan offers diversity and why it makes sense to duct fire the proposed CCGT. He testified that without the CCGT Vectren South's wholesale power margin will decline because the coal units are not competitive. Mr. Games also addressed criticisms from the OUCC that Vectren South's cost estimate is not reliable. Finally, he addressed recommendations made by the Industrial Group relating to contracting for construction of a CCGT and explained that Vectren South did consider alternative scrubber technology at A.B. Brown.

c. Matthew E. Lind responded to the criticisms of the modeling in the 2016 IRP, 2017 Update Analysis and PROMOD NPV Analysis that were been raised by OUCC witnesses Boerger, Alvarez and Aguilar; by ICC witness Hayet; and by Joint Intervenors' witness Comings. He defended the modeling that Vectren South performed under his direction and supervision as robust. He said that in the IRP there were 7 different computer-generated portfolios based on different interdependent scenario assumptions sets. He said the modeling conclusions, out of the multiple portfolios considered, including seven (7) portfolios optimized for lowest NPV share one common characteristic: the retirement of the A.B. Brown Generating Station Units by 2024 and the construction of a large CCGT to replace that retired baseload capacity. Mr. Lind said the 2017 Update Analysis further confirmed this result. He also observed that beyond the seven cost optimized portfolios, many other portfolios were analyzed for cost and risk and the differences among those portfolios all relate to whether and to what extent Vectren South continues also to burn coal and constructs renewable resources in addition to the large CCGT. He said that none of the criticisms leveled by witnesses Boerger, Alvarez, Hayet or Comings change that result. He also said that Mr. Hayet's alternative modeling, needed several corrections. Mr. Lind challenged Mr. Coming's criticisms that the Preferred Portfolio ("Portfolio L") does not possess the lowest NPV, claiming the lowest NPV would be achieved by switching completely to a large and new CCGT and abandoning coal altogether.

d. Perry M. Pergola addressed concerns raised by Alliance Coal witness Jude Clemente regarding Vectren South's proposal to retire its coal powered units and replace them with the proposed CCGT. He said the U.S. natural gas industry, including of Texas Gas Transmission are resilient and reliable. He cited examples of the reliability and resiliency shown in both the production and interstate pipeline sectors in the natural gas industry. He also testified about the efforts which are taking place across the natural gas industry to improve environmental performance.

e. **Steven A. Hoover** testified in response to criticisms raised by Industrial Group witness Gorman and ICC witness Medine regarding Vectren South's decision to self-build the gas transmission line to interconnect the proposed CCGT with Texas Gas Transmission, LLC's existing interstate pipeline. He also addressed testimony of OUCC witness Alvarez about whether a project included in Vectren South's Electric TDSIC 7 Year Plan is needed to serve the CCGT.

f. **J. Cas Swiz** testified in response to various proposals made by OUCC witnesses Blakley and Aguilar related to the cost recovery and accounting authority requested by Vectren South for the Culley Unit 3 environmental projects and the new CCGT. He also responded to proposals made by Industrial Group witness Gorman regarding the CCGT request and the recovery of deferred costs approved in 44446 via an ECA mechanism. He also responded generally to statements made by ICC witness Hayet related to the impacts of the Tax Cuts and Jobs Act of 2017 on the modeling assumptions utilized Mr. Lind.

g. **Michael J. Hicks** defended his economic analysis against certain criticisms by Sunrise witness Davis.

h. **Paul S. Farber**, Principal at P. Farber & Associates, LLC, reported on his review of ammonia based scrubber technology, including the many potential operating challenges associated with the adoption of this technology. He responded to the testimony of Sunrise witness Dombrowski regarding the possibility of retrofitting one or both of the A.B. Brown units with ammonia-based scrubber technology. He also responded to the testimony of OUCC witness Aguilar regarding the feasibility of technologies other than wet limestone scrubbing for the Brown Units.

i. **Richard F. McMahon, Jr.**, Vice President of Energy Supply and Finance at the Edison Electric Institute, testified that the electric industry is moving to reduce emissions. He testified, from a national perspective, about: 1) the importance to investors of Environment, Social, and Governance factors and how that impacts access to capital markets and the cost of capital for electric companies; and, 2) related national trends of coal plant closures and the disclosure of climate targets and emission reduction goals by individual electric companies.

j. **Peter J. Hubbard**, Manager at Pace Global Energy Services, LLC, addressed the criticisms asserted by Alliance witness Clemente involving the potential cost impacts of Vectren South replacing some or all of its coal fleet with a CCGT and the potential uncertainties in the U.S. natural gas market that could increase natural gas prices more than estimated in the 2016 Vectren South IRP and the subsequent market outlook update in 2017.

k. **Richard G. Smead**, Managing Director, Advisory Services at RBN Energy LLC, responded to the testimony of Alliance witnesses Clemente and

Nasi and ICC witness McConnell who voiced opposition to Vectren South's proposal to construct a CCGT to replace existing coal-fired capacity. Mr. Smead said there is resilience of gas in general, gas can be a fully reliable and resilient power-generation fuel. He also testified about the specifics of the natural gas market and industry in the region relevant to the proposed CCGT that render it particularly well-protected. Mr. Smead presented the NGC study as support, in some instances highlighting elements within that study that directly contradict certain representations made by one or more of the three witnesses.

l. **Thomas L. Bailey**, Vectren South's Director of Industrial Sales & Economic Development, responded to Joint Intervenors witness Comings' criticism that Vectren South has refused to provide necessary information to analyze future load growth of specific customers. He also responded to concerns raised by Mr. Comings regarding the amount of demand response, as defined by large industrial customers selecting Vectren South's interruptible contract rider, included in its modeling

m. **Justin M. Joiner**, Vectren South's Director of Regulatory Policy and Midcontinent Independent System Operator Affairs, addressed certain issues within the direct testimony of OUCC witnesses Alvarez and Boerger, and Joint Intervenors' witness Comings regarding current developments at MISO in regards to resource adequacy, market reform, the mechanics of the MISO Planning Resource Auction, the importance of capacity being located within the same Zone as the load for which it serves, year over year Planning Reserve Margin Requirement, and the MISO Generator Interconnection Process and importance of priority. He said market reforms are likely to drive future prices for capacity and energy higher, and will support more efficient, better ramping units that can respond to market conditions.

ii. Joint Intervenors

a. **Michael Goggin**, Vice-President of Grid Strategies LLC, testified on behalf of Citizens Action Coalition, Valley Watch, and Sierra Club in response to Alliance Coal witness Michael Nasi and ICC witness Charles D. McConnell testimony regarding grid resilience. Mr. Goggin is the Vice President of Grid Strategies LLC and was recently re-elected to NERC's Planning Committee. He previously served on NERC's Operating Committee and Standards Committee and has over a decade of experience in electric reliability.

Mr. Goggin testified that the Commission should not base its decision on any purported resilience attributes of coal. Mr. Goggin provided his opinion that Messrs. Nasi and McConnell incorrectly claim that retaining "fuel secure" or "baseload" coal-fired units is necessary to ensure the resilience of the electric grid. Disagreeing with Messrs. Nasi and McConnell, Mr. Goggin stated that neither of the agencies primarily tasked with ensuring grid resilience—FERC and

NERC—recognizes "resilience" as a well-defined metric and neither claims coal-fired generation contributes to greater resilience of the electric system. Instead, Mr. Goggin testified that FERC unanimously rejected as unsupported a proposal from the Department of Energy to provide special compensation to coal-fired units in the name of purported resilience attributes, particularly "fuel security." Mr. Goggin noted that, since unanimously rejecting that unsupported proposal, FERC continues to work to "first achieve a common understanding of what resilience is in the context of the bulk power system." He stated that regional grid operators participating in FERC's ongoing study of resilience are unanimously opposed to proposed market interventions and thus far have concluded that existing markets and reliability standards already ensure resilience.

Mr. Goggin continued to testify that Messrs. Nasi and McConnell did not accurately and completely describe NERC's work on resilience. He stated that Mr. McConnell relies on a letter from the now-resigned CEO of NERC that does not reflect "the rich and nuanced findings of NERC technical studies and reliability assessments." JI Ex. 5, Att. MG-1. Though not mentioned by Mr. McConnell, he stated that the NERC letter concludes that "gas-fired units, variable generation, storage, and other resources can provide similar reliability services" as coal resources. Mr. Goggin testified that in NERC's extensive study of the retirement of large conventional coal and nuclear units, the organization has concluded that "reliability of the system can be maintained or improved as the resource mix evolves." He said that NERC's findings include the agency's "Resilience Framework" which details how the organization's ongoing activities already address all aspects of electricity resilience. Like FERC, he stated that NERC's recent Winter Reliability Assessment concluded that U.S. power markets were prepared for extreme winter weather. Mr. Goggin testified that nowhere in NERC's years of study and assessment has it found that retaining coal-fired units is necessary to ensure reliability in the face of disruptive events. Mr. Goggin said that NERC's body of work in fact shows that no single type of resource is essential, because reliability and resilience can be met by many combinations of technologies and resources, including combinations without any coal-fired generation.

Mr. Goggin testified that Messrs. Nasi and McConnell inappropriately focus on "fuel secure generation" when, in fact, the risk of generation shortfalls during extreme weather or other events has been primarily caused by power plant equipment failures. Mr. Goggin stated that coal-fired plants have been affected by equipment failures during extreme events as much or more than other generation types. By way of example, Mr. Goggin noted that PJM identified coal plant equipment failures as a significant cause of power outages during the "bomb cyclone" storm of winter 2017/18; and NERC, PJM, and others also found coal plant equipment failures were one of the largest causes of outages during the 2014 Polar Vortex event. Mr. Goggin further testified that coal plants exhibited high outage rates during a cold snap leading to rolling blackouts in Texas in 2011, accounting for 40% of all outages despite representing just 23% of installed capacity. Mr. Goggin testified that, both then and in more recent events, older units experienced much higher rates of forced outages, including older coal units. Mr. Goggin concluded that, through their focus on "fuel security," Messrs. Nasi and McConnell incorrectly attribute value to coal plants that in fact were primary contributors to outages during disruptive events.

Mr. Goggin further stated that coal plants are actually vulnerable to fuel supply risks. For example, he said that several years ago, many MISO coal plants were at risk due to rail congestion limiting coal deliveries; droughts have limited coal deliveries by barge and forced units offline due to cooling water restraints; and flooded coal piles during hurricanes have caused reduced outputs.

Responding to Mr. McConnell's claim that coal units provide frequency support services, Mr. Goggin testified that coal plants fail to contribute to a range of NERC-identified essential reliability services. Mr. Goggin stated that NERC's conclusion that 90% of conventional generators fail to provide sustained primary frequency response. Further, Mr. Goggin testified that coal plants are highly inflexible, making them poorly suited to respond to challenges of all types. As an example, Mr. Goggin pointed to MISO's Independent Market Monitor, which recently concluded that coal plants account for over 80% of generator deviations from scheduled output levels, imposing significant costs and reliability concerns on the system. Referring to JI Ex. 5, Att. MG-3, the Silverstein/Grid Strategies Resilience report, Mr. Goggin testified that, like all generation types, coal units fail to deliver all essential reliability services needed for a reliable and resilient grid in all circumstances. He stated that coal units are significantly vulnerable to grid disturbances affecting essential plant equipment, that frequency or voltage disturbances could cause cascading failure of large generators, and that system recovery can actually be faster with high levels of flexible renewable energy resources rather than inflexible thermal units.

Responding to Mr. Nasi's reliance on a single NETL report, Mr. Goggin testified that the NETL report did not actually measure system resilience and has been widely criticized. He said that the NETL report purports to evaluate resilience during the January 2018 "bomb cyclone" by comparing the electricity output of different energy sources in PJM during the bomb cyclone event to the preceding 26 days of December 2017. Mr. Goggin opined that increased utilization during the weather event is not a metric of resilience, but rather a testament to the poor economics of coal generation. He said that because significant coal generation capacity was idle or underutilized prior to the weather event owing to high operating costs, that capacity was available for increased use as energy prices rose. Mr. Goggin testified that this increased utilization does not show greater resilience, just that the coal units are more expensive. Mr. Goggin urged that system resilience during the bomb cyclone is better measured by outage rates of different resources during the weather event. He argued that, on that measure, coal plants' performance was relatively poor, with most outages caused by equipment failures.

Mr. Goggin testified that, unlike coal plants' performance, renewables and wind generation in particular provided up to 40% greater output than average during the bomb cyclone, many times above the levels grid operators count on for power system planning purposes. Mr. Goggin stated that wind generators consistently provided high output during earlier cold snap events as coal generators experienced high levels of forced outages. Finally, Mr. Goggin testified that PJM issued a statement that the NTEL "report's overall conclusions are incorrect" and concluded that NETL misrepresented the contribution of coal plant dispatch during the bomb cyclone. He said that recent media reports have uncovered that the NETL report was subject to political influence to overstate the value of coal generation.

Mr. Goggin further argued against Mr. McConnell's testimony, stating that it ignores that coal-fired units exhibit significant vulnerabilities, susceptibility to outages, and inability to provide essential services during disruptive events; and fails to address the fact that reliability and resilience must be addressed at a system level, accounting for transmission, distribution, reserve margins, and other system parameters. He further criticized McConnell's reliance on a PJM scenario analysis and a report from the American Coalition for Clean Coal Electricity ("ACCCE"), an advocacy group representing major American coal producers. Mr. Goggin testified that PJM's scenario analysis actually shows that it is not essential to have any one type of generation in the mix, as shown via Att. MG-3. Mr. Goggin stated that the ACCCE analysis assumed large quantities of coal retirements in PJM, very large quantities of simultaneous gas disruption, and the addition of no new resources or import of power to PJM. He said that only under these unrealistic assumptions in which nearly 30% of the system's total capacity is suddenly available without any adjustment in the system do problems arise. Beyond the highly improbable circumstances assessed, Mr. Goggin urges that the analysis has little relevance.

In sum, Mr. Goggin argued that concerns about generation resilience voiced by Messrs. Nasi and McConnell do not provide a sound basis for decision in this case. Instead, Mr. Goggin proposed that resilience must be assessed on a system-wide, context-specific basis that includes an assessment of different measure to mitigate the risks of disruptive events. Beyond the other flaws in Messrs. Nasi and McConnell's testimony, Mr. Goggin opined that their discussion of resilience lacks these critical elements.

4. Commission Discussion and Findings

A. CPCN for CCGT and related relief

i. Introduction

This CPCN request is governed by Ind. Code ch. 8-1-8.5, which requires Vectren South to meet its burden of proof on numerous statutory elements, and requires us to make several specific findings, before Vectren South's CPCN request can be approved. Failure to prove even a single required statutory element, or our inability to make any required finding, is fatal.

As we explain in detail below, we deny Vectren South's CPCN because there are several statutory elements as to which we believe Vectren South did not provide sufficient proof, and there are accordingly several required findings that we cannot make on the evidentiary record before us.

We are mindful of our regulatory role, and whenever possible, we avoid supplanting a utility management's decisions with our own. That said, with respect to CPCN requests for major capital cost projects such as Vectren South proposes here, our regulatory oversight is critical for the protection of customers.

Before the CPCN procedures outlined in Ind. Code ch. 8-1-8.5 were enacted in the 1980's, utility investors and management risked their own funds to construct generating stations, and only when complete did they petition this Commission for a determination the new facilities were used and useful. If the Commission disagreed the utility might be denied both recovery of and return on some or all of its investment. Accordingly, utilities were financially at risk if they misread the future when deciding about investments in major capital projects.

Generating stations have useful lives lasting many decades. Thus, there will always exist a risk that the future need for a certain amount of generation or a certain kind of generation may be misestimated. However, Ind. Code ch. 8-1-8.5 to some extent has shifted risk from utilities to customers.

Ind. Code ch. 8-1-8.5 did not change the ratemaking paradigm under which the more rate base a utility has, the more return it may earn. This paradigm incentivizes utility investors, and the management they hire, to build new generating stations. Once these proposed additions are approved by this Commission, utility investors have little risk of loss if they over-estimate the amount of new capacity required or they have misestimated the amount and/or type of generation that will remain useful and economic for the next four to six decades.

Given these realities, our regulatory responsibility requires us to carefully scrutinize CPCN requests, especially when, as here, we are considering a nearly complete replacement of a utility's generation portfolio. Utilities must fully meet their burden of proof and are not entitled to the benefit of the doubt. In order to protect customers from imprudent investment, we will hold utilities to their burden of proof to satisfy each element of the statute.

Vectren South is the smallest investor owned electric utility in Indiana and for many years has had the highest monthly residential bills in our Annual Residential Bill Survey. Vectren South's load has been declining. Yet, Vectren South proposes to build a new 850 MW generator, which is over 60% of its current generation capacity (including purchased power). Even the 700 MW alternative Vectren belatedly raised in rebuttal is over 50% of its current generation capacity. These facts are unprecedented. Never before has any utility sought a CPCN under Ind. Code ch. 8-1-8.5 to build new generation equal to anything close to 50% or 60% of its existing fleet.

To avoid being considerably overbuilt, Vectren South proposes to retire existing major generation units that it built relatively recently. A.B. Brown Units 1 and 2 went in service in 1979 and 1984 respectively. They will be 44 and 39 years old, and not fully depreciated when Vectren South proposes to retire them in 2023. Appendix 3 in our 2018 Statewide Analysis lists the 36 operating coal generation units in Indiana. A.B. Brown Unit 2 is fifth newest, and Unit 1 is tied with two other units for the eleventh newest. Appendix 2 of the 2018 Statewide Analysis lists the 25 Indiana coal generation retirements since January 1, 2010. The average age at retirement of those 25 units was 59 years.

We are not saying that newer coal generating units may not be retired. We understand that many factors, including substantiated regulatory requirements, market economics, etc. may combine to justify such retirements. We are only saying that in this case, given (1) Vectren South's size and current bills, (2) its proposal to retire generation units leaving undepreciated capital costs it will seek to recover from customers, and (3) its proposal to replace them with a new generating unit that, by itself, will represent over 70% of Vectren South's future generation fleet, Vectren South must provide sufficient, credible, and well-tested evidence to support its CPCN request.

As we explain in detail below, the evidence does not satisfy the burden of proof required by the CPCN statute. Specifically:

- The evidence does not sufficiently demonstrate necessity, which is the threshold requirement for granting a Certificate of Public Convenience and *Necessity*. Ind. Code § 8-1-8.5-2. Vectren South has not demonstrated that it is presently required by regulatory mandate or otherwise to construct the proposed facility.

- We do not find sufficient evidence to support the necessary findings on the potential for Vectren South to purchase energy or capacity from either the MISO market or other utilities. Ind. Code. § 8-1-8.5-4(1).

- Ind. Code § 8-1-8.5-4(2) requires us to consider whether Vectren South has other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources. Vectren South's evidence does not rule out these alternatives sufficiently for us to approve the significant investment Vectren South proposes in a new CCGT. Rather, it raises more questions about Vectren South's current level of investment in these alternatives.

- Ind. Code § 8-1-8.5-5(b)(1) requires that we find Vectren South's construction estimate of $781 million to be a best estimate. The evidence does not support that finding.

- Ind. Code § 8-1-8.5-5(b)(2)(A) requires a finding that Vectren South's proposal is consistent with our 2018 Statewide Analysis. However, as we explain below, Vectren South's proposal appears contrary to our Analysis in regard to resource and fuel diversity.

- In the alternative, Ind. Code § 8-1-8.5-5(b)(2)(B) requires a finding that Vectren South's proposal is consistent with its own IRP, but as a precursor to such a finding we must first approve Vectren South's IRP in this case. Ind. Code § 8-1-8.5-5(d). On the evidence before us we cannot approve Vectren South's IRP. There are simply too many questions and doubts concerning whether its IRP, and the modeling supporting it, fairly considered all resource alternatives. There is ample reason to be concerned that the IRP's design and screening preordained a large CCGT outcome. Certainly, we know the capital cost assigned to the CCGT option in the IRP modeling was materially understated compared to Vectren South's updated cost estimate.

- Ind. Code § 8-1-8.5-5(b)(3) requires that we find public convenience and necessity, which necessarily means we must consider the public interest. Here again, the evidence is insufficient to support approving Vectren South's proposal on the grounds of public interest. The evidence is replete with significant near future costs that will befall Vectren South electric customers independent of our decision in this case. When we add to those already daunting costs the potential bill impact of the capital cost of the proposed CCGT, plus the capital cost of a new gas line to feed the CCGT, plus the annual fixed cost to operate and maintain that gas line, the impact on customers is enormous. Additionally, in considering public interest this case we cannot ignore the significant impact on other areas of the economy of southern Indiana, long-term environmental concerns, and the risk to Vectren South and the local economy of its service territory from a long-term bet on natural gas for over 70% of its generation for many decades. All these factors weigh against approving Vectren South's CPCN request.

- Finally, because Vectren South's proposed CCGT is more than 80 MW, Ind. Code § 8-1-8.5-5(e) requires that we find that Vectren South's cost estimates for engineering, procurement, and construction are the result of competitive bidding, unless it is commercially impractical, and that we consider both reliability and solicitation of bids from others to supply electricity. Vectren South's estimate for engineering costs was not based on competitive bidding. As the Petitioner, it is Vectren South's responsibility to fulfill this statutory requirement. Vectren South elected to delegate this task to B&V. The B&V witness (Ms. Fischer) testified it was commercially impractical for it (*i.e.* B&V) to obtain competitive engineering bids, because as B&V is an engineering firm its competitors would not give it such bids. That in no way proves it was commercially impractical for Vectren South to solicit competitive engineering bids. Further, as we explain below, the evidence does not support a conclusion that Vectren South's proposal is a reasonably reliable means of serving its customers, or a conclusion that Vectren South sufficiently polled the market for alternative sources of future supply.

Our inability to make the required finding for any one of the above requires denial of Vectren South's CPCN request.

ii. Ind. Code § 8-1-8.5-2 (necessity for certification)

While Vectren South claims that its request for a CCGT is consistent with its IRP, consistency by itself does not mean automatic Commission approval. Pub. Ex. 1, p. 13, ll. 1-13. The Commission must find that all elements of the statute are met. One of the required elements to support a CPCN is expressed in its title – a utility must show that there is a necessity for the requested project. In this case, Vectren South claims a necessity that is not supported by the evidence.

Vectren South requests approval for an 850 MW plant that it justifies by retiring currently active units. As we set forth in the section discussing refurbishment, Vectren South chose a much more expensive alternative by ignoring refueling of units and a smaller CCGT. Pub. Ex. 1, p. 15, ll. 1-15. To the extent that there is a need, it is one of Vectren South's own making.

Vectren South has excess supply, and its capacity position remains long even after meeting its MISO PRM. Pub. Ex. 2, pp. 2, 6-7. As shown by Mr. Alvarez, Vectren South has had a declining load profile for a period of years. *Id.* Vectren South's assertion of prospective load growth is not supported with evidence, while its declining load is a trend. From 2013 – 2017, Vectren South has lost an average of 50 MW of load per year. Pub. Ex. 2, p. 4. Its total load has decreased by 150 MW, at the same that MISO's PRM has been declining. *Id.* It lost contracts with several municipals, and one of its large industrial customers chose to pursue co-generation rather than continue to get energy from Vectren South. *Id.*

While Vectren South's 2016 IRP projected a 0.5% increase in load every year out to 2036, Pub. Ex. 2, p. 5, it has also announced its expectation that demand would be relatively flat, at .1%. *Id.* Vectren South has more than enough capacity and has excess supply it can sell. Pub. Ex. 2, p. 9. We agree with Mr. Alvarez that it is imprudent for Vectren South to shut down units in pursuit of an oversized CCGT. *Id.* Vectren South needs to consider alternatives, including smaller unit additions, alternative environmental upgrades, replacement of fewer units, the addition of renewables, and procurement of conservation and load management. Vectren South did not properly evaluate these alternatives in its 2016 IRP or in its 2017 update for this case. This is underscored by the fact that should we approve its request, Vectren South will have excess capacity of 17.30% UCAP, approximately 125.50 MW. Pub. Ex. 2, pp. 14-15. Should Vectren South's negative growth continue, "Vectren will double its excess capacity at great cost to its ratepayers." Pub. Ex. 15, ll. 11-12. We find that given the evidence, Vectren South does not have the demand to justify a plant of this size.

iii. Ind. Code §§ 8-1-8.5-4 and -5

In order to succeed on its CPCN request, Vectren South's evidence must permit us to make all the required findings under Ind. Code §§ 8-1-8.5-4 and -5. As explained below, there are many such required findings that we cannot make on the evidentiary record before us.

a. Ind. Code § 8-1-8.5-4(1) (current and potential arrangements with other electric utilities for interchange, pooling, purchase, or joint ownership)

In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities." Ind. Code § 8-1-8.5-4(1).

Like other Indiana utilities, Vectren South is an active participant in the MISO energy and capacity markets, and any inquiry under Ind. Code § 8-1-8.5-4(1) must begin with recognition of that fact. *See N. Ind. Pub. Serv. Co.,* Cause No. 43396, 2008 WL 2434152 at *25 (IURC May 28, 2008). Yet throughout its testimony in this case, Vectren South has raised concerns about the reliability of MISO markets, suggesting that it would be too risky for Vectren South to rely on MISO markets for any extended period of time to meet energy or capacity needs. As described further below, *see* our risk analysis discussion, Vectren South seems to take a one-sided view of market risk, treating purchases from the market as inherently risky without acknowledging that over-building its generating capacity also creates risk for its ratepayers: namely, the risk that Vectren South is over-spending on excess capacity that it does not need in light of the availability of the MISO markets to fill any shortfalls. *See* JI Ex. 2 at 20-21. Vectren South was so committed to ensuring that purchases from the MISO market would not be a part of the resource portfolios that it modeled for this case that it incorporated into its modeling an arbitrary cap of 10 MW after 2023 (the year that its proposed gas plant would begin operating) on the amount of capacity that the model would be allowed to select as being purchased from the MISO market in any given year. Tr. at C-90-91 (confirming Strategist modeling capped capacity purchases at only 10 MW per year). Vectren South also assumed unreasonably high increases in MISO market capacity prices, which biased its modeling in favor of building a large new resource such as the proposed CCGT. *See* JI Ex. 2 at 23-25. On rebuttal, Vectren South sought to defend its assumptions about future increases in MISO capacity prices with reference to proposed market changes in MISO, Pet. Ex 20-R, p. 8, but many of these MISO market changes have not actually been implemented and there is no guarantee that they ever will be, Tr. I-65, l. 12-Tr. I-71, l. 24.

Ind. Code § 8-1-8.5-4(1) also calls on us to evaluate the potential for the utility to purchase power from another utility or jointly own generation with another utility. We note that Vectren South considered and rejected both possibilities in its analysis of responses to the RFP that it conducted for this case. As noted by Joint Intervenors' witness Comings, however, the terms of Vectren South's RFP were clearly designed to favor new-build gas plants that would be wholly owned by the company, which would have strongly discouraged potential bidders from offering Power Purchase Agreements or joint ownership proposals. *See* JI Ex. 2 at 45-46.

Accordingly, we do not believe that we have a sufficient record before us to make findings on the potential for Vectren South to purchase energy or capacity from either the MISO market or other utilities. These deficiencies in the record provided by Vectren South contribute to our conclusion below that its application does not satisfy the requirements of Chapter 8.5.

b. Ind. Code § 8-1-8.5-4(2) (other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources)

We also find the CPCN application for the CCGT must be rejected as a result of our analysis under Ind. Code § 8-1-8.5-4(2). The statute requires that the utility consider extension of the life of its units, or refurbishment, as part of the CPCN. In this case, Vectren South discounted those options out of hand, instead falling back on its IRP conclusion. Tr. B-27 ll. 4 – 16. As we note in our discussion regarding whether Vectren South provided a "best estimate", a failure to fully examine these options means that Vectren South has not met the statutory requirements for the grant of a CPCN.

(1) Refurbishment

In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze:

(1) Retain Coal at Vectren South's existing plants and invest in refurbishments;

(2) Retain the agreement with Alcoa for Warrick 4;

(3) Refuel the Brown unit(s) with gas;

(4) A blended option, such as refueling one or more Brown units to gas and building a smaller CCGT;

(5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and

(6) Retain its Broadway Avenue Unit 2.

Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11, ll. 12 -16. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the FGD units at a cost of approximately $350 million. Pub. Ex. 3, p. 7, ll. 7-15. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.*, Pub. Ex. 3, ll. 6-13. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7, ll. 16-21. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both Brown units.

Mr. Alvarez testified that Vectren South only evaluated a wet limestone, forced-oxidation FGD. He noted that Vectren South witness Mr. Chapman dismissed the opportunity for Vectren South to explore other replacement alternatives and that Mr. Chapman said that it makes more sense to retire the A.B. Brown units and invest in new CCGT technology. Mr. Alvarez stated that Vectren South needs to provide support and justification, including studies and analyses that explore all cost effective options to extend the life of the generating units paid for by its ratepayers.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9, ll. 12 -19. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of Vectren South units. Tr. B-25, l. 11 - B-26, l. 12. Vectren South did not fully model the conversion of one of the Brown units in its rebuttal testimony, admittedly leaving out risk. Tr. E-45 l. 9 – E-46, l. 13.

ICC witness Mr. Hayet confirmed that Vectren South updated its 2016 IRP to include the addition of a new scrubber at the A.B. Brown units. He pointed out that a 2017 B&McD study showed that the A.B. Brown units' scrubbers could operate for a maximum of 45 years (until 2023 and 2030 for Brown units 1 and 2, respectively). A copy of this report was attached to Mr. Games' testimony as Att. WDG-1. Mr. Hayet modeled this scenario in his economic analyses. ICC witness Ms. Medine testified that although Vectren South modeled the scrubber retrofit in its 2017 update, it made no effort to identify the lowest cost scrubber retrofit or to consider alternative scrubber or water treatment options.

Sunrise Coal witness Ms. Dombrowski provided testimony about several alternative options that Vectren South did not consider. Specifically, Ms. Dombrowski investigated ammonia-based SO2 systems, and she presented a substantial report in her testimony located in Att. KD-2. Ms. Dombrowski testified that ammonia-based scrubbing is commercially available and has been deployed in the United States on a limited basis and widely in Poland and China. She said that ammonia-based scrubbers can achieve 98% or greater SO2 removal. She concluded that ammonia-based scrubbers are a promising alternative to limestone-based SO2 scrubbing and that ammonia-based scrubbing merits investigation by Vectren South and inclusion in its economic modeling.

Mr. Chapman admitted on cross-examination that that although Vectren South proposes to make investments in the Culley 3 facility, (which will be 50 years old in 2023) to comply with environmental regulations, it does not plan to make similar investments in the two younger Brown units, which will be 37 and 44 years old in 2023. Mr. Chapman said that Vectren South had not mentioned the need to replace the scrubbers on the Brown units in its 2016 IRP because at the time it believed the decision to retire the units would be the same even without considering the scrubbers. Vectren South witness Mr. Lind also confirmed on cross-examination that the 2016 IRP retirement modeling did not include replacement of the Brown units' scrubbers, but that the issue was considered in the 2017 update. Mr. Games stated on cross-examination that B&McD did a preliminary estimate of the cost to replace the Brown units' scrubbers, but only analyzed a wet limestone forced oxidation option. He stated this was based on looking at the coal quality burned by the units. He further stated that Vectren South and B&McD talked about dry sorbent injections and other FGD processes, but there were issues with those and B&McD recommended that the wet limestone scrubber was the best alternative for high sulfur coal.

We cannot be certain about the technological or economic viability of these proposed alternatives because, as Mr. Chapman admitted, Vectren South did not model any replacement of the Brown units' scrubbers in its 2016 IRP and only modeled a single replacement option in its 2017 update for this case. This is not sufficient to comply with the requirement in Ind. Code § 8-1-8.5-4(2) that Vectren South consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. We find this surprising considering Mr. Chapman's testimony that Vectren South has made a very large investment in its existing coal fleet to bring Southwest Indiana into attainment with environmental regulations. This investment came at a high cost to Vectren South's customers, who, with the exception of the Industrial Class, have the highest electric rates in the state. We agree that Vectren South has made a substantial effort to comply with state and federal environmental regulations. We do not agree however, that Vectren South should now cause its customers' rates to increase even further by constructing a large, new CCGT after its customers have paid such high rates to bring the units into environmental compliance.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we do not trust Vectren South's economic modeling results to verify this claim. Vectren South has not presented sufficient evidence to convince us that constructing a CCGT at a total cost that may exceed $1 billion plus saddling its customers with an additional $270 million of stranded assets that Vectren South customers have already paid to bring into environmental compliance is a reasonable course of action. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report of the flaws in their modeling for the 2016 IRP and the 2017 update and to present a more thorough analysis that meets all of the statutory requirements to seek a CPCN for new construction.

(2) Conservation

We have previously recognized that "[s]aving energy is the most cost-effective way of meeting future energy supply needs and has the corresponding benefit of reducing the need to build additional generation capacity." *Comm'n Investigation re Demand Side Mgt.*, Cause No. 42963, Ph. 2, 2009 WL 4886392, 281 P.U.R.4th 51, p. 30 (IURC Dec. 9, 2009). In fact, while we "recognize[d] the need to approve additional generation capacity as necessary to meet the needs of customers and ensure Indiana's ongoing economic success, [we] also recognize[d] that an important component of long-term planning for Indiana's generation needs is the effective utilization of DSM programs by jurisdictional utilities that have a duty to serve their ratepayers in a cost effective manner." *Id.* This is in concert with our obligations under Ind. Code § 8-1-8.5-3 to develop statewide analyses to determine long-range needs for expansion of electric generation. Specifically, our statewide plan must examine "the comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, conservation (including energy efficiency), load management, distributed generation, and cogeneration." In addition, a utility's IRP shall "assess a variety of demand side management and supply side resources to meet future customer electricity service needs in a cost effective and reliable manner." Ind. Code § 8-1-8.5-3(e)(2).

The current and projected levels that Vectren South is achieving and plans to achieve are indisputably continuing to decline beginning with 2018 through the end of Vectren South's IRP planning period in 2036. Vectren South's 2016-2017 savings goals amounted to approximately 1% of eligible retail sales on an annual basis, 0.93% for 2018-2020, 0.75% for 2021-2026, and finally down to 0.50% for 2027-2036. JI Ex. 3, p. 14, ll. 10-19; JI CX 28; JI Ex. 3, Public Workpaper 2; Tr. G-26, ll. 7-25. Joint Intervenors presented an analysis finding a "total savings potential reach[ing] 2% of eligible retail sales by the year 2023" which "can be maintained at or above that level for many years." JI Ex. 3, p. 40, ll. 1-4. Joint Intervenors argued that because Mr. Mellinger's "analysis was not a comprehensive review of all measures, this estimate of higher savings is very likely conservative." *Id.*, ll. 4-7. Joint Intervenors noted that Mr. Mellinger's analysis finding 2% of eligible sales worth of savings is more in line with other Midwestern utility efficiency investments. *Id.*, pp. 43-44.

The availability of additional energy efficiency was hotly contested between Vectren South and Joint Intervenors. Joint Intervenors' analysis of additional savings totaling 44,000 MWh/year emphasized commercial lighting, especially linear bulbs, as having large potential totaling 19,000 MWh/year. *Id.*, p. 14, 29, Tr. G-41, ll. 15-24. Vectren South argued that the commercial lighting savings cannot be depended on in the long term due to "rapid progress in lighting efficiency and codes and standards", Pet. Ex. 8-R, p. 4, ll. 19-24, relying on a Department of Energy ("DOE") report entitled "Energy Savings Forecast of Solid-

State Lighting in General Illumination Applications" to support its claim. JI CX 30. Mr. Mellinger also relied upon this DOE report as a basis for his lighting projection, JI Ex. 3, fns. 35, 39, 43, but arrived at a very different conclusion than Vectren South regarding the readily available commercial lighting potential. *See* JI CX 30, p. vii, Fig. ES.1. Vectren South stated the DOE report estimates that 80% of the installed stock will be LED by 2030, JI CX 29 (Vectren South Response to CAC Data Request 12.2(b)), yet Vectren South failed to distinguish that the focus of Joint Intervenors' analysis was on the linear type of LEDs, which the DOE report shows as having the largest potential for savings. JI CX 30, p. 25, Fig. 4.5. Vectren South also argued a distinction between LED lighting potential and cost effective lighting for utilities, Tr. G-43, ll. 11-19, but the DOE report notes it reflected continued utility investment as part of its forecast, JI CX 30, p. vi, and still projects dramatic cost decreases in LED lighting over time, particularly between now and 2025. JI CX 30, p. 76, Fig. D-2. Vectren South further argued that the International Energy Conservation Code ("IECC") from 2009, 2012, and 2015 shows erosion in the commercial lighting baseline. JI CX 29 (Vectren South Response to CAC Data Request 12.2(c)). A review of the IECC, however, shows these codes only apply to new construction projects. International Code Council, 2009, 2012, 2015 IECC, Section 101, Scope and General Requirements. Vectren South's 2018-2020 plan also shows that commercial and industrial ("C&I") new construction accounts for a total of 2,840 GWh out of the entire C&I portfolio total of 48,233 GWh (or 6%), so the excluded amount is not significant. JI Ex. 3, Public Workpaper 1, Tab 2018-20 Planned Measures. A review of the Indiana Energy Code shows too that it is based on ASHRAE 90.1 2007, which predates the earliest IECC code referenced by Vectren South.

Vectren South also relied on its Market Potential Study ("MPS") to estimate energy efficiency potential in its service territory over the planning period. Pet. Ex. 8-R, pp. 12-14. Joint Intervenors argued that MPSs tend to be inherently conservative, and Mr. Mellinger found that to be the case with Vectren South's. JI Ex. 3, pp. 45-46. Joint Intervenors argued that MPSs tend to understate potential by focusing on measures that are known today, failing to recognize the full potential from custom measures and programs, not fully accounting for higher savings as technologies evolve or costs decrease, failing to include all benefits from efficiency, failing to account for market transforming effects, failing to account for new ways to approach markets like midstream programs with lower administrative costs, and recognizing only a portion of economic potential after it is arbitrarily whittled down to what is "achievable". *Id.* at 48-49. Joint Intervenors presented evidence regarding emerging technology as a large amount of savings that is rarely captured by an MPS. *See* JI CX 32 at 15 ("Cadmus' 2012 study for the Iowa Utility Association...finds [emerging technology] could increase electric market potential (i.e., maximum achievable potential) by up to 3%...KEMA's 2010 study for Xcel Energy Colorado finds that economic potential increases by 24% when [emerging technologies] are included."). Vectren South agreed that MPSs' do not assess unknown technologies and stated "potential studies are most valuable in the short-term". Pet. Ex. 8-R, p. 13, ll. 14-18. Furthermore, Mr. Mellinger found that Vectren South's MPS omitted several measures that could have brought in substantial savings, made no estimate regarding emerging technologies, and did not consider any new or alternative program designs. *Id.*

Joint Intervenors provided evidence that 2% of eligible sales by 2021 through 2036 is reasonable, and the Commission finds there could be potential additional savings beyond Vectren South's efficiency projection of 0.93% for or 2018-2020, 0.75% for 2021-2026, and finally down to 0.50% for 2027-2036.

The second main dispute around conservation in this proceeding relates to Vectren South's assumptions for the cost of energy efficiency used in Vectren South's modeling runs, which Joint Intervenors argue biased the model's selection of energy efficiency. A cross exhibit was introduced comparing Vectren South's 2018-2036 net present value for energy efficiency at $285.81/MWh versus a net present value of $164.43/MWh after Joint Intervenors altered certain assumptions to the efficiency costs Vectren South made that Joint Intervenors found unreasonable coming in at $164.43/MWh. JI CX 27. The difference between the two net present values amounts to 174%. *Id.*

Joint Intervenors argued that their corrections to just the first initial 0.25% of eligible retail sales that Vectren South plugged into the model reflects an overstatement of costs by about 28%. JI Ex. 3, p. 7, l. 3-p. 9, l. 3. Joint Intervenors argued that because Vectren South escalates the cost of every subsequent block of 0.25% eligible retail sales worth of savings off this first initial 0.25%, a 28% overstatement of costs in first block of 0.25% eligible retail sales worth of savings would carry forward to every single subsequent block of 0.25% of energy efficiency that Vectren South modeled. *Id.* Joint Intervenors objected to several assumptions Vectren South made to the initial block of savings. First, Joint Intervenors argued that it was inappropriate for Vectren South to use a planning program expenditure (JI Ex. p. 7, ll. 7-13), when Vectren South's actual program expenditures come in at an average of 88% of Vectren South's planning expenditures forecast. JI CX 15-16, JI CX 18-24. Joint Intervenors presented evidence that only in 2016 did Vectren South's actual expenditures come in over its planned budget. *Id.,* Tr. G-16, ll. 9-14. Vectren South argued that its use of a planning figure for cost results in a $0.02/kWh difference, while Joint Intervenors argue this 15% difference can make a significant difference in economic optimization resource models, especially if other factors in the model contain errors. JI Ex. 3, p. 7, ll. 10-13; JI CX 15-16, JI CX 18-24; Tr. F-78, l. 20-F-79, l. 2. Second, Joint Intervenors disagreed with Vectren South's assignment of this 2016 planning cost to just the first block of 0.25% of savings, when the 2016 planning cost represented 1.3% eligible sales worth of energy efficiency, i.e. the cost was for 1.3% of eligible sales which is 5.2 blocks worth of savings, not 0.25% of eligible sales or just 1 block of savings in Vectren South's model. JI Ex. 3, p. 8, Table 3; Tr. F-95, ll. 6-14; Tr. F-97, l. 11-F-98, l. 7. Joint Intervenors argued this mismatched application of a cost for 1.3% of eligible sales to a block amounting to only 0.25% of eligible sales resulted in an overstatement of the initial block 1 and subsequent blocks used in Vectren South's modeling of approximately 4.2%. JI. Ex. 3, p. 8. Third, Joint Intervenors noted that Vectren South's expression of 2016 planned costs were in 2015 dollars, meaning Vectren South included an additional year of inflation in error. JI Ex. 3, p. 7. Vectren South admitted to this error. Pet. Ex. 8-R, p. 7, ll. 7-12.

Finally, Joint Intervenors argued that Vectren South's development of the first block of savings applied the wrong net to gross ("NTG") ratio to block 1. JI Ex. 3, p. 8, ll. 8-14. Vectren South does not dispute its use of a NTG ratio of 0.80 rather than 0.84, which was Vectren South's actual evaluated figure in 2017. Pet. Ex. 8-R, p. 5, l. 20-p. 6, l. 7. Vectren South states because its NTG ratio "has been both above and below 0.80", Vectren South "rounded" its 0.83 NTG from its 2015 evaluation down to 0.80. *Id.* Vectren South admits that the difference between the 0.84 NTG ratio and Vectren South's 0.80 NTG ratio amounts to a 5% difference in the cost of net savings. Tr. F-98, ll. 18-25.

As to Vectren South's cost for energy efficiency used in its modeling, Joint Intervenors argue that Vectren South has not adequately addressed the data quality issue the Commission's Director of Resource Planning identified in the 2016 Draft and Final IRP Reports. Specifically, Joint Intervenors noted the Director's statements about Vectren South's reliance on Dr. Stevie's cost escalation figures using EIA 861 data, rather than relying on Vectren South's own empirical data. The Director said that he "appreciates the analysis performed by Dr. Stevie but is concerned that if the adjustments made to correct for admitted serious data limitations is sufficient to overcome the problems being addressed. Drawing strong policy recommendations in such circumstances is probably not warranted . . . . Hopefully, future analysis will be more reliant on empirical data derived from DSM's effects by Vectren customers." JI Ex. 2, Attach. TFC-5 at 37 and Att. TFC-6 at 43. Vectren South admits that it continues to rely on Dr. Stevie's energy efficiency cost analysis using EIA 861 data, Pet. Ex. 8, p. 8, l. 13-p. 9, l. 14, p. 10, ll. 14-19, and confirmed that they "only updat[ed] one portion of his analysis for purposes of this case." Tr. F-100, ll. 7-11. Vectren South admits it continues to rely on Dr. Stevie's analysis for its assumption of a 4% compound annual growth rate ("CAGR"), meaning it assumed that costs of energy efficiency grow 4% each and every year of the analysis. Tr. F-99, l. 2-12. Joint Intervenors argue Vectren South's continued use of Dr. Stevie's 4% CAGR, when its own empirical data from 2013-2017 shows a growth rate closer to 0.4-0.8% per net kWh saved, results in a significant overstatement of costs. JI Ex. 3, p. 9, l. 4-p. 12, l. 5. Vectren South argues its empirical data actually shows a 7.5% CAGR if 2011, 2012, and 2018 are added into this analysis of cost growth between years. Pet. Ex. 8-R, p. 6, ll. 8-25. At the hearing, however, Vectren South admitted that its calculation of a 7.5% CAGR included the use of planned figures for the 2018 data instead of actuals, Tr. G-15, l. 24-Tr. G-16, l. 2, and that 2011 and 2012 were very different insofar as they were Vectren South's first two full years of program delivery and included the participation of industrial customers who were later provided the opportunity to opt out of utility-sponsored DSM programs. Tr. G-7, l. 24-Tr. G-8, l. 16; Tr. G-15, ll. 19-21. JI CX 25 presents another look at the data where excluding just the 2018 planned figures from Vectren South's revised analysis shows a 3.0% CAGR, or comparing 2012, 2014, or 2015 to 2017 shows a negative CAGR, meaning costs decline between those years on a cost per kWh basis. Ultimately, Joint Intervenors' witness Mellinger argues that holding all other assumptions the same and looking just at the use of the 4% CAGR that Vectren South assumed rather than the 0.8% from the "empirical data derived from DSM's effects by Vectren South's customers" shows increases in costs by about 6% in 2020, 24% in 2025, and 46% by 2030. JI Ex. 3, p. 11, l. 18-p. 12, l. 5.

We agree with Joint Intervenors' identification of errors in Vectren South's assumptions for the cost of energy efficiency. We find that Vectren South's overestimation of the cost of energy efficiency by 28% likely biased it from effectively competing against supply-side resources in Vectren South's model. Overall, we reaffirm our statements that conservation is one cost-effective method to provide service to Vectren South's ratepayers and has the corresponding benefit of reducing the need for expensive generation projects. Joint Intervenors have provided significant evidence that additional, untapped savings potential exists in Vectren South's service territory. We find that Vectren South's consideration of conservation was inadequate and flawed, and its conclusions appear to have had the effect of biasing against conservation and reinforcing Vectren South's preferred CCGT.

(3) Load Management

A quick overview of current load management methods available to Vectren South (with the second highest percentage of sales to industrial customers) shows interruptible tariffs addressing just 3.2% of Vectren South's peak, while NIPSCO (with the highest percentage of sales to industrial customers) is able to shave off 16.8% of its peak with interruptible tariffs. JI Ex. 2, Att. TFC-21, p. 10. Vectren South then bases its forecast for future load management opportunities off these current low participation levels, and that was just for the runs where load management was allowed to compete at all. JI Ex. 2, p. 36; Pet. Ex. 6, Strategist workpapers. Thus, Vectren South's future projection for load management looks bleak, similar to its current levels of load management.

But, evidence shows there is a reason for the current low participation in Vectren South's interruptible riders – onerous penalties and unnecessary restrictions creating a failed market of Vectren South's own doing, despite ample evidence in the record showing the potential. *See* JI Ex. 2, Att. TFC-21 at 10, 34.

Vectren South's main interruptible rider, Rider IC, has a penalty equal to 10 times the capacity credit per kVa, if a customer fails to provide 1 MW worth of demand response within 10 minutes. JI CX 36. Rider IC also arbitrarily restricts participation by only allowing 2 of the 6 relevant rate classes to be eligible for the tariff, and Vectren South still does not allow for third party aggregators who can help aggregate customers who cannot provide an entire 1 MW at a time with other customers who cannot provide an entire 1 MW at a time to collectively provide that 1 MW to Vectren South during a peak management event. Without aggregation services, Vectren South's arbitrary requirement for 1 MW of curtailment is too large a threshold especially under the risk of a penalty at 10 times the capacity credit. We have previously "strongly encouraged" our jurisdictional utilities to "explore opportunities with [aggregators or curtailment service providers] which may further enhance participation in demand response by customers of all sizes, classes and sophistication". *Commission Investigation*, Cause No. 43566, 284 P.U.R.4th 225, 2010 WL 3073664 at Order p. 47 (IURC July 28, 2010). Eight and one-half years later, Vectren South has failed to take seriously this encouragement from the Commission, and its customers have been deprived of adequate investment in load management.

We need not look further than the northern part of the State to see the effect these restrictions can have on participation in the tariffs, where NIPSCO shaves off approximately 16% of its peak by offering a variety of tariffs that are set up to genuinely encourage participation. *Compare* JI CX 36 with JI CX 39. Vectren South's restricted tariffs were set up to fail and bias against a method of providing electric service that is reliable, economical, and efficient.

(4) Renewable Resources

Vectren South's preferred plan in this case envisions 4 MW of solar online in 2018 and an additional 50 MW in 2019 with no additional utility-scale wind. Pet. Ex. 1 at 8, ll. 3-5. This results in an energy portfolio that decreases renewable energy from 4.4% in 2015 of Vectren South's energy portfolio to 3.8% in 2036. JI CX 4. After examining the evidence of record, it supports our conclusion that Vectren South exaggerated wind and solar cost estimates in its resource modeling to favor its proposed resource path.

In the 2016 IRP, Vectren South chose Portfolio L (even though Portfolio D with 400 MW of wind was cheaper), which is the resource path Vectren South is pursuing now: 4 MW of solar in 2018 and an additional 50 MW in 2019, and no utility-owned wind. JI Ex. 2, Att. TFC-3, p. 11, Table 2. For the 2017 update of the IRP, Vectren South updated the solar costs, but failed to update the wind costs. Pet. Ex. No. 5, pp. 13-15. The 2017 update to the model also imposed several constraints, including not allowing the Strategist model to economically choose or optimize any early retirement, conversion, and refuel options for coal units, and it froze in the assumption that Warrick Unit's operating life would extend through 2023, which inevitably altered how renewables could compete in the model. *Id.*

For the cost of solar, Vectren South assumed costs for solar capital and fixed O&M that run contrary to the experience of the last decade and the consensus of the solar market experts, an issue that stakeholders flagged for Vectren South in its 2016 IRP stakeholder process. JI Ex. 2, Att. TFC-3, p. 33. In the 2016 IRP stakeholder process, stakeholders asked Vectren South to evaluate the NREL ATB forecast instead as it is a better benchmark that properly reflects the cost of solar around the country. The NREL ATB is relied upon by MISO and derives its forecast based upon "14 system price projections from 8 separate institutions with short-terms projections made in the past six months and long-term projections made in the last three years" including institutions that represent both public (e.g. the U.S. Energy Information Administration and the International Energy Agency) and private research firms (e.g. Bloomberg New Energy Finance and GTM Research). JI Ex. 2, p. 38, pp. 41-42. JI Witness Comings shows a confidential comparison between the NREL ATB forecast and Vectren South's forecast for solar. It demonstrates that Vectren South's assumed costs for solar capital and fixed O&M are unreasonably high and do not reflect the experience of the last decade and the consensus of solar market experts. JI Ex. 2-C, p. 41, Figures 21 and 22.

Vectren South also assumes higher capital costs for wind, sticking with the high costs it used in the 2016 IRP and failing to update them for the 2017 update to the IRP, despite stakeholders offering this exact criticism as part of Vectren South's 2016 IRP stakeholder process. JI Ex. 2, Att. TFC-3, pp. 32-33. In its 2016 planning analysis, Vectren South did not have project specific information that one would receive through a recent all-source Request for Proposals. We agree with Joint Intervenors' assertion that it would have been more appropriate for Vectren South to use the NREL ATB forecast since it did not issue an all-source Request for Proposals to get project specific information. The NREL ATB wind cost forecast is a survey of over 160 wind experts, which "may be the largest elicitation ever performed on an energy technology in terms of expert participation." JI Ex. 2, p. 39, ll. 3-6 (quoting the authors of the study by NREL). NREL applies the results of this expert survey to estimate the future levelized cost of energy in various locations. Instead, Vectren South failed to address this criticism to its 2016 IRP wind capital cost assumption and used the same high cost wind assumption from the IRP in its 2017 update.

Even using the 2016 IRP high capital wind costs in the 2017 update, a portfolio with 400 MW of wind and the retirement of Culley Unit 3 was selected as the least cost portfolio over Vectren South's preferred one, i.e., Portfolio D won over Vectren South's preferred Portfolio L. JI Ex. 2, pp. 15-16; Pet. Ex. No. 7, p. 19 and workpapers. Portfolio D's overall score with the wind also scored better than Portfolio L's score in Pace Global's 2017 updated risk analysis. *Id.*

Nonetheless, Vectren South chose not to go with Portfolio D because (1) the Company determined the portfolio would include "a significant capacity deficit" due to the wind; (2) the Company was uncertain of the future capacity credit for wind in MISO; and (3) the Company claimed keeping Culley 3 operational would provide "additional flexibility to meet future growth." Pet. Ex. No. 5, p. 16. We find that this was an inappropriate step by Vectren South to essentially count capacity risk twice against wind by including the factor in the quantitative risk assessment then using that same factor to reject a better-performing portfolio (according to its own risk assessment methodology) on a qualitative basis. Compare Pet. Ex. No. 5, p. 16 and Tr. F-28, ll. 1-19.

It is also questionable that the Company would cite to uncertainty with regard to wind capacity credits as a rationale not to pursue additional wind resources when it readily and willingly forecasts other uncertain factors in its modeling. Tr. F-27, ll. 6-16. It even projected a wind capacity factor for this case. *Id.* Many elements of electric system modeling have uncertainty, such as fuel prices, capital costs, capacity factors, and peak load; and the Company just forecasts estimates for these elements. Vectren South should have done the same for wind capacity credits, rather than asserting Vectren South's unwillingness to forecast this uncertainty as a reason to reject a portfolio with 400 MW of wind. JI Ex. 2, pp. 15-16.

The Commission finds renewables to represent another potentially viable and promising method for providing reliable service to customers, and Vectren South's overestimation of costs for renewable energy and its rejection of a plan with 400 MW of wind for unsubstantiated reasons weighs against approval of Vectren South's proposed new generation project.

As shown above, Vectren South's petition for construction fails here under our Ind. Code § 8-1-8.5-4 evaluation of Vectren South's current and potential arrangements to efficiently use the grid to access power and in our consideration of the other, better methods available for providing reliable, efficient, and economical electric service. Since Vectren South must satisfy all elements of the statute, this is sufficient grounds to deny Vectren South's CPCN request. However, as explained below, the Commission further finds that Vectren South also failed to satisfy the mandates of Ind. Code § 8-1-8.5-5.

c. Ind. Code § 8-1-8.5-5(b)(1) (best estimate of construction)

We are guided by Ind. Code § 8-1-2-0.5, which mandates we use all practicable means to "create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services present and future generations of Indiana citizens." We note that our discussion on modeling bears heavily on our analysis in this section. Under Ind. Code § 8-1-8.5-5(b)(1), the Commission must "make a finding as to the best estimate of construction, purchase, or lease costs" presented in a CPCN request. Vectren South's estimate does not meet this standard on multiple fronts.

Vectren South's argument is that the CCGT at $781 million is the cheapest option for customers but given the infirmities in its modeling and failure to include all costs, this assertion cannot stand. Vectren South's case does not present an accurate and complete estimate of the cost of its proposed project. Pub. Ex. 1, p. 6, ll. 7-12. Without this crucial information, Vectren South has not met its burden to show that it has presented the best estimate of the project.

For purposes of modeling the cost of the CCGT to weigh the economics of potential projects, Vectren South's consultant, B&McD, used a +/- 50% in the determination of their estimate. Tr. A-35, ll. 9-18. In turn, Vectren South used B&McD's projected cost, which ranged between $580 – $650 million, for the purpose of evaluating the potential projects. Tr. A-36, l. 19 – A-38, l. 20. Use of the lower estimates inappropriately advantaged Vectren South's self-build CCGT and use of the modeling based on an outdated estimate renders Vectren South's economic modeling suspect.

For purposes of supporting Vectren South's $781 million CCGT cost estimate proposed to this Commission, Vectren South's B&V consultant, Diane Fischer, offered the only evidence on Vectren South's attempt to obtain a best estimate for the equipment that supported the overall $781 million CCGT cost estimate. In Attachment DMF-7, Ms. Fischer explains the basis of the +/- 10% cost estimate. Pet. Ex. 10, Att. DMF-7, p. 4. Notably, the cost estimate report states the cost estimate is based on a +/- 10% accuracy for engineering, equipment and construction costs, but that the switchyard component of the estimate is only a Class 4 estimate. *Id.* The report further explains that, while B&V obtained competitive bids for major equipment and construction services, other elements of the project were estimated based on B&V's experience and knowledge of the markets and industry conditions. The report notes that, the estimate is "based on preliminary information and as such is to be considered a non-binding price opinion." The report further notes that the estimate could be impacted by other factors including labor market changes, final site conditions, noise requirements, and the final project schedule. *Id.*

These limitations prevent us from concluding that Vectren South has proffered its best estimate of the project. First, Vectren South's cost estimate appears to be based on dated bid responses that we cannot find remain reliable. Mr. Games testified that the RFI issued to OEMs were done prior to Vectren South's 2016 IRP, which indicates those estimates may be approaching three years old. Second, we are concerned that at least one component of the estimate, the switchyard, is supported by a Class 4 estimate, which carries a much lower range of accuracy than the +/- 10% estimate associated with Vectren South's overall estimate.

Most importantly, however, we find that the $781 million cost estimate is incomplete and cannot be construed as the best estimate as required by the statute. As we note in our public interest discussion, Vectren South's $781 million estimate does not include several other major cost components that are integral to the project. For example, the $781 million estimate does not include the approximately $87 million capital expense for the gas line that Vectren South proposes to construct to fuel the CCGT, and Vectren South confirms that the $87 million estimated pipeline expense carries only an estimated accuracy of +/- 20%, meaning that the upper limit of the pipeline's cost is $104 million. Tr. H-13, l. 7-14; Tr. E-9, ll. 6-11. The $781 million cost estimate also does not include the costs to reserve capacity on the gas pipeline. We find that the statute requires us to take a holistic view of the project in determining whether Vectren South has met its burden to demonstrate that it has provided a best estimate. Because the project cannot operate without the construction of the gas pipeline, we must factor into our analysis whether Vectren South has provided the best estimate of the cost of the *entire* project, including the gas pipeline and associated gas capacity reservation. We find that Vectren South failed to present adequate cost information for those components. For all of these reasons, we cannot make a finding that Vectren South provided the best estimate of construction, purchase and lease costs in accordance with Ind. Code § 8-1-8.5-5(b)(1).

d. Ind. Code § 8-1-8.5-5(b)(2)(A) (consistency with Commission's statewide analysis)

Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. That Report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that Report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other

> unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

As we explain elsewhere, Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites seems contrary to the concept of resource diversity.

While Vectren South's proposal does diversify its baseload fuel from 100% coal to 70% gas and 30% coal, the evidence does not convince us that such a large, long-term shift from one fossil fuel to another fossil fuel puts Vectren South on the path to appropriate fuel diversity. The evidence suggests that Vectren South's proposal would increase its reliance on fossil fuels from 95.6% in 2015 to 96.2% by 2036. JI CX 4. When we look at the long-term plans of other Indiana utilities as reported in the 2018 Statewide Analysis, none propose to retain such a heavy reliance on fossil fuels, and none propose to become concentrated 70% in a single fuel.

On page 5 of the Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

As we discuss in more detail elsewhere, Vectren South's proposal appears to deprive it of future flexibility in utility resource decisions in order to minimize risks. To the contrary, Vectren South's proposal saddles it and its customers with paying for an expensive, long-lived generating plant that seems likely to constitute the vast majority of Vectren South's resource fleet for a long time. The burden on customers to pay a return on and return of that capital expense seems likely to significantly narrow Vectren South's options for any future change of course to adapt to circumstances and changes.

In explaining the importance of sound long-range planning on page 56 of the Statewide Analysis, it says, "The credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." Nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

Accordingly, we cannot find from the evidence that Vectren South's proposal for a new CCGT is consistent with the Commission's Statewide Analysis.

e. Ind. Code § 8-1-8.5-5(b)(2)(B) (consistency with Vectren South's IRP)

The Legislature has decided that before we approve any utility proposal to construct new generation, we must approve or disapprove, in whole or in part, the "utility specific proposal submitted under section 3(e)(1) of this chapter[.]" Ind. Code § 8-1-8.5-5(b)(2)(B), (d). This is the utility's IRP. Ind. Code § 8-1-8.5-3(e)(1). For the reasons detailed below, we disapprove Vectren South's 2016 IRP.

(1) Vectren South failed to properly assess all resources to meet customer needs.

First, Vectren South failed the Legislature's directive to "assess[] a variety of demand side management and supply side resources to meet future customer electricity service needs in a cost effective and reliable manner." Ind. Code § 8-1-8.5-3(e)(2). As detailed elsewhere, Vectren South failed to properly assess MISO market purchases as a supply side resource, taking a one-sided view of market risk, making unsupported assumptions about the risk and cost of MISO market purchases, and refusing to consider more than 10 MW of annual purchases after 2023. Similarly, as detailed in our discussion of conservation, Vectren South failed to consider the demand side resource of energy efficiency: overstating the cost of energy efficiency programs, underestimating the benefits of those programs, and relying on a Market Potential Study that did not properly assess all available energy efficiency options. Finally, as detailed in discussion of conservation and load management, Vectren South's IRP contained unreasonable and unsupported biases against Demand Side Management.

Ultimately, Vectren South failed to properly consider all resources available to serve customer needs, because the company had already decided to construct a CCGT. Vectren South's IRP and current certificate application rest on subjective, qualitative factors designed to make sure the company's desired outcome was achieved. This is further evidenced by Mr. Games' rebuttal testimony indicating that the company *already* knows the results of the yet-to-be-commenced 2019 IRP. Pet. Ex. 4-R p. 26 ("When the 2019 IRP modeling is concluded and again recommends construction of a CCGT[.]").

(2) Vectren South's use of a multi-stage modeling process lacked transparency and credibility.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

Vectren touts the frequency with which its various modeling exercises and analytical steps selected a CCGT as confirmation that a CCGT is the most appropriate resource option. *E.g.*, Vectren Brief at 5. Commissioners in Michigan recently cautioned against drawing just such a conclusion. April 27, 2018 Order at 66, *In re DTE Elec. Co.*, Case No. in MPSC No. U-18419 (Mich. Pub. Serv. Comm'n Apr. 27, 2018), at 66 ("The Commission expects that an effective IRP should produce results, under certain scenarios, that show the preferred course of action is not actually the best option. This is how we know the IRP is testing the robustness of the preferred course of action by examining how it performs under various assumptions, even if those assumptions may seem unrealistic today."). What Vectren touts as confirmation of its results has been judged elsewhere to potentially "give the impression that modeling results were steered or forced into a pre-determined result." *Id.*

Vectren South's modeling also has grave infirmities that render it unusable. At the outset, Mr. Games testified that Vectren South sent an RFI to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 l. 9 – E-91, l. 21. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27, l. 24 - A-28, l. 6. But the IRP did not include all costs for the proposed CCGT, and modeling for this case did not include the costs for the necessary gas pipeline. Tr. D-5, l. 19 – D-7, l. 1. The modeling also did not consider the $20 million in annual costs that will be required to run the CCGT's pipeline. Tr. E-9, ll. 19-21. Should the $781 million estimate go 10% higher, the additional pipeline construction costs would push the total to over $900 million, without the annual operating costs for the pipeline. *Id.* Yet none of these potential costs or cost overruns were included in Vectren South's modeling. And Mr. Games admitted that Vectren South's "preferred portfolio," which includes the CCGT, is "a little over $1 billion." Tr. F-2, ll. 1-9.

Dr. Boerger for the OUCC, and Mr. Hayet and Ms. Medine for ICC, criticized Vectren South's 2017 update of selective scenarios from its 2016 IRP modeling. (Pub. Ex. 3, p. 11, l. 3 – p. 18, l. 9; ICC Ex. 2, p. 8, l. 11 – p. 18, l. 3; ICC Ex. 1, p. 8, l. 8 – p. 20, l. 2). Dr. Boerger testified that Vectren South did not consider viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1, l. 16 – p. 2, l. 1, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5, ll. 2-5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50 ll. 11-14. Vectren South also did not allow for proposals of joint projects to be built at its Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73, ll. 18-21. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections... unduly limited[,]" Tr. D-85, ll. 10-17, but Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86, ll. 2-9. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14, ll. 11-16. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18, l. 2 – p. 19 l. 12. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15, l. 25 – E-16, l. 25. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36, l. 19 – A-38, l. 20; Tr. D-7 l. 9 – D-8, l. 9. When questioned why B&McD did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35, ll. 9-18; Tr. C-61 - C-62, C-74, ll. 6-13. B&McD's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-36, l. 19 – A-38, l. 20. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98, ll. 3-14.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the Brown units, biased the results by adding 200 MW of solar that the OUCC had not requested. Tr. D-12, l. 23 – D-13, l. 22. Then, Vectren South used this distorted rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15, ll. 6-24. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16, l. 20 – D-17 l. 22, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14, ll. 4 – 25.

Because Vectren South was seeking CCGT construction costs before the IRP (now three years ago), there is a reasonable inference that Vectren South's modeling was already biased to a pre-determined conclusion. So while Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case screened out multiple less-expensive alternatives. Adding insult to injury, the cost estimates in the modeling were understated to make the CCGT option appear more favorable. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14, ll. 4 – 25. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request. And we find that Vectren South blaming the +/-50% cost estimate as the reason for cost discrepancies is unreasonable for a well-established technology like a CCGT.

However, Vectren South has sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. Additionally, we note the process used by NIPSCO in its 2018 IRP that used an RFP as part of its IRP process to identify opportunities that could be acted upon swiftly, without the kind of delays warned about in Vectren South's rebuttal testimony. Hence we direct Vectren South to use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and include an actionable RFP that can result in smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity appears to be needed.

(3) Vectren South failed to address the Director's criticisms of the 2016 IRP.

Following criticisms from the Director's 2016 IRP Report, Vectren South updated its risk analysis by removing metrics for "Remote Generation Risk" and "Net Sales," which appeared to be ill-defined and one-sided, respectively. Ex. GV-4 at 2-4. Yet Vectren South's decision to pursue its preferred portfolio in the 2016 IRP relied, in part, on these factors. JI Ex. 2, p. 18.

In the original risk analysis accompanying Vectren South's 2016 IRP, each portfolio was ranked as "red," "yellow," or "green" for each risk metric. Commenting on those rankings, the Director's Report observed that "distinctions between rankings (red/yellow/green) seemed arbitrary." JI Ex. 2 Att. TFC-6, p. 41. The Director's Report noted that "[t]he arbitrariness, combined with the significant effects on overall rankings, raises concern[.]" *Id.* Vectren South's updated risk analysis simply switched the three arbitrary color assignments with three arbitrary numerical values: red, yellow, green became zero, five, and ten. Colors were swapped for numbers in the "Cost-Risk Trade-Off," "Largest 24/7 Power Source," "Number of Technologies," and "Local Economic Impact" metrics. Pet. Ex. 7 Att. GV-4; Tr. at D-51. These four factors, combined, account for just over 45% of each portfolio's overall score. This means that nearly half of each portfolio's overall score is derived from an arbitrary scoring approach Vectren South falsely claimed to have remedied. The arbitrary results of this approach cannot support Vectren South's preferred portfolio.

The Director's 2016 IRP Report also called out a data quality issue regarding some of Vectren South's critical assumptions for the cost of energy efficiency, warning that "[d]rawing strong policy recommendations in such circumstances is probably not warranted" and expecting that "future analysis will be more reliant on empirical data derived from DSM's effects by Vectren South customers." JI Ex. 2, Att. TFC-5, p. 37 and Att. TFC-6, p. 43. Vectren South nonetheless relied on all but one of the faulty assumptions derived from that poor data set to project DSM costs. The most egregious was Vectren South's refusal to correct the cost growth assumption of DSM over time, applying a 4% compound annual growth rate, when its own empirical data shows a growth rate closer to 0.4-0.8% per net kWh saved. JI Ex. 3, p. 9, l. 4-p. 12, l. 5. Holding all other assumptions the same and looking just at the use of the unrealistic 4% compound annual growth rate Vectren South assumed rather than the 0.8% from the "empirical data derived from DSM's effects by Vectren South's customers" shows increases in costs by about 6% in 2020, 24% in 2025, and 46% by 2030. JI Ex. 3, p. 11, l. 18-p. 12, l. 5.

Finally, the data in the analyses presented to the Commission has become stale, because Vectren South failed to fully update all analyses with new inputs. As detailed in our discussion of risk, we find that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing.

The Integrated Resource Planning process requires each utility to "make continuing improvements to its planning[.]" JI Ex. 2, Att. TFC-6, p. 1. By refusing to address the Director's criticisms, Vectren South has failed to make the required improvements. This mandates disapproval of the 2016 IRP, and denial of this CPCN application.

For these reasons, we disapprove Vectren South's 2016 IRP. Approval of Vectren South's IRP is a prerequisite to our approval of Vectren South's proposal to construct new generation. Ind. Code § 8-1-8.5(b)(2)(B), (d). Therefore, our conclusion below must be that the application does not satisfy the requirements of Chapter 8.5. We note that our disapproval of Vectren South's IRP "shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity." Ind. Code § 8-1-8.5-5(d).

f. Ind. Code § 8-1-8.5-5(b)(3) (public convenience and necessity)

Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In that case, the court approved the Commission having included in its public interest determination consideration of the impact on employment in the coal industry. *Id.*

(1) Bill Impact

Vectren South has had the highest electricity bills in the state since 2011, based on a monthly consumption level of 1,000 kilowatt hours. JI Ex. 1 at 7-8, especially Figure 3 (citing CAC Administrative Notice Ex. 2-8); Pet. Ex. 1-R at 27. Despite Vectren South arguing this is the result of unavoidable costs, Vectren South's residential customers paid, on average, $21 per month more in 2018 than the next highest bills among Indiana's jurisdictional electric utilities, NIPSCO. JI Ex. 1, p. 5, ll. 20-23 (citing CAC Admin. Notice Ex. 1). The burden of these inordinately high bills is particularly harsh given that Vectren South's service territory includes areas that experience higher poverty levels and lower household income than the average across Indiana, JI Ex. 1 at 9-10.

While modeling is helpful in producing a single number—net present value—on which alternatives may be compared, it is important that we recognize the limitations of such modeling. Mr. Lind acknowledged that in the models, capital cost recovery is levelized. Tr. p. C-99, ll. 5-12. He conceded that the models are therefore not reflective of what rates and bill impact will be. Tr. p. C-100, l. 24 – C-101, l. 5. This is because while capital cost recovery is levelized in modeling, the bill impact on customers is front loaded in ratemaking. Thus, in ratemaking, capital cost recovery hits customers the hardest in the first year because in that year customers pay return on the entire capital investment, plus return of a small part of that investment. In the second and succeeding years, the bill impact slightly declines each year because each year customers pay back a small part of the investment, and the remaining investment in the next year on which customers must pay a return declines over the useful life of the property.

Vectren South provided no evidence of the customer bill impact of its plan, saying that it is not now seeking any recovery from customers and there are too many variables that go into ratemaking for it to predict the rate impact. However, in its post-hearing brief Vectren South conceded it is possible to do rough calculations now of the future bill impact of the capital cost component. Indeed, Vectren South performed such a calculation on a hypothetical $500 million capital cost, assuming today's tax rates and the same rate of return as the Commission allowed Vectren South in its last rate case. Using those same assumptions, the Coal Parties' brief did the same calculation on a $868 million capital cost ($781 million for the CCGT plus $87 million for the new lateral pipeline), and showed that the bill impact in the first year would be $114,779,488. Add to that another $20 million annually for firm transportation service, and the total first year cost customers must bear becomes $134,779,488. We have checked the math and it is correct. That equals about 23% of the total annual revenue requirement we authorized for Vectren in its last base rate case. *In re Vectren,* Cause No. 43839, 2011 WL 1690057, 289 P.U.R.4th 9, Order p. 57 (IURC Aug. 27, 2011). Of course, the $781 million is a ±10%, so it could become $876 million. The $87 million is a ± 20%, so it could become $108 million.

In addition to the above costs, Vectren South customers face numerous additional costs in the coming years, independent of our decision in this case. For example, a majority of the $497.5 million of TDSIC costs over the next seven years includes partial collection through a fixed customer charge. *Petition of S. Ind. Gas & Elec. Co. for Approval of TDSIC*, Cause No. 44910, 2017 WL 4232049, Final Order at 34-35 (IURC Sept. 20, 2017)(combining the $446.5 million in TDSIC replacements and upgrades and rate case deferred recovery totaling $51 million for smart meter/AMI investments.) Additionally, regardless of the outcome of this case Vectren South customers also face: (i) $40,507,010 of deferred MATS costs (Pet. Ex. 13, Att. JCS-1, Schedule 8); (ii) $67,283,812 of Gross New Capital Investment as of 12/31/2017 (Pet. Ex. 13, Att. JCS-1, Schedule 2); (iii) $111,000,000 in costs to close the ash pond at A.B. Brown (Retherford, Tr. p. B-69); and (iv) between $14 million and $34 million for the cost of closing the Culley east ash pond (Pet. Ex. 9R, Att. AMR-4R, Table 5-3).

If it were unequivocally clear that Vectren South's plan would be the least expensive for ratepayers in the long run, our decision might be different. But, for a variety of reasons we discuss elsewhere that is not unequivocally clear. Accordingly, we find that potential bill impact of Vectren South's plan weighs against our approval of it.

(2) Other economic impacts

Vectren South presented very limited economic impact evidence. Michael Hicks, Vectren South's economic impact witness, did not perform any economic impact study specific to area of the plants Vectren South proposes to close or the Vectren South electric service area. Rather, Dr. Hicks did a historical analysis of the impact on employment of other coal plant closings in other places in Indiana. From that analysis, Dr. Hicks concluded that "closing a coal-fired generation facility does not have a statistically significant change in employment of the county and adjacent counties in which the coal fired power plant is located." Pet. Ex. 14, p.4, ll.10-12.

However, it is not clear whether most of the closings in Dr. Hicks' small sample are comparable to the closings that Vectren South proposes. Dr. Hicks specifically mentions Morgan, Cass, Vigo, and Dubois counties as places where electric plants have recently closed, but he does not identify the plants. From our own regulatory expertise, we know that the plant that closed in Dubois County in 2016 was the Jasper Municipal generating plant which was only 14.5 MW in size, a tiny fraction of what Vectren South plans to retire. We also know that the closure in Cass County was the Logansport Municipal generating plant, which was only 43 MW. The units in Morgan County were IPL's retirements of its Eagle Valley generators. While the 341 MW that IPL retired at Eagle Valley is a significant fraction of what Vectren South plans to retire, Morgan County borders Indianapolis, and the Eagle Valley station is located less than 20 miles from the I-465 loop around Indianapolis. Dr. Hicks' map indicates his sample also included closures that border other large, metropolitan areas. Dearborn County borders the Cincinnati metropolitan area, Floyd County borders the Louisville metropolitan area, and Lake County borders the Chicago metropolitan area. In his rebuttal, Dr. Hicks conceded that he did no analysis of the lost jobs in Knox County which supplies all the coal for the coal plants that Vectren South proposes to retire.

In its 2016 IRP Vectren South included an Economic Impact Study that was specific to Vectren South's plans and the local areas surrounding the plants Vectren South plans to close. Drs. Alhenawi and Bayar who performed that study concluded that the closing of A.B. Brown Units 1 & 2 would have a negative 1-year Output Impact of $178,778,538. Pet. Ex. 5, Att. MAR-1, p. 837. They similarly found that closing Culley 2 would have a negative 1-year Output Impact of $22,962,042. *Id.*

Alison Davis, testifying for Intervenor Sunrise Coal, performed an Economic Impact Study that was specific to the effect on Knox and surrounding counties from the potential loss of coal mining and coal transportation jobs from the closing A.B. Brown Units 1 & 2. Dr. Davis noted that a rural county like Knox County "is much less diversified than one would see in urban places. For example, in Knox County, in 2015, the largest industries contributing to the local economy, in terms of overall sales, were truck transportation, coal mining, and electric power transmission." Sunrise Ex. 1, p. 4, ll. 12-15. Dr. Davis found a negative economic impact of $498 million. *Id.* p. 6, ll. 18-20. Her report also notes a negative impact on local and state tax base would result from the switch from Indiana coal to out-of-state natural gas that Vectren South proposes.

Vectren South itself has long recognized the importance of coal production to the economy of southwest Indiana. Less than five years ago, when Vectren South was seeking permission to invest millions in the A.B. Brown station so it could comply with new MATS standards and continue to operate, Mr. Chapman testified that, "[t]he continued employment of hundreds of miners, and truckers and other Hoosiers whose jobs are directly or indirectly dependent on local coal production has long been of great importance to the economy of Southwest Indiana." Tr. p. A-44, l. 25 – p. A-45, l. 4. We remain concerned with job losses caused by these proposed retirements. This was underscored by testimony presented by several witnesses at the Field Hearing. JI Ex. 1 Att. KLO-4, pp. FH-B 25-27. Ultimately, based on the evidence, we conclude that a significant adverse economic impact would likely result from Vectren South's proposal.

(3) Environmental concerns

We are well aware that the Indiana and U.S. economies, indeed the world economy, will likely shift to relying significantly less on carbon emitting processes. The exact path by which that will happen cannot be known. It may be driven, in varying degrees by voluntary, collective action, by political pressure, by economic incentives and/or disincentives, and by government mandate. It may involve any combination of substituting lower carbon emitting technology in place of higher emitting technology or substituting non-carbon emitting technology for carbon emitting technology. Vectren South's preferred plan is a long-term bet (with customer's money rather than the company's) on substituting a carbon (and methane) emitting fuel (natural gas) for its current carbon emitting fuel (coal). Vectren South advances this plan at the same time that other utilities are finding that substituting non-carbon emitting technology for carbon emitting technology is a feasible and preferred path. Given the current state of uncertainty, suddenly switching to having 70% of Vectren South's capacity based on carbon emitting natural gas seems unduly risky. A more flexible approach that leaves the ability to adapt to future circumstances seems more prudent, particularly when it appears more likely to mitigate the rate impact on customers.

Mr. Games testified that 458 coal units consisting of over 52 GW of capacity have been retired in the U.S. since 2012, and the majority is replaced with natural gas generation. But there are indications that trend may not continue. The record reflects that other utilities, even some in Indiana, are now planning coal retirements with non-gas replacements. Pet. Ex. 4, p. 9, ll. 4-10. We do not deny that has been the historical trend, but at present, it is unclear how strongly that trend will continue. The record reflects that other utilities, even some in Indiana, are now planning coal retirements with non-gas fueled replacements.

Ms. Medine, ICC's witness, pointed out that at the end of period modeled by Vectren South, the proposed CCGT would be only 15 years old, yet a new CCGT has a useful life expectancy of 30 to 40 years. ICC Ex. 1, p. 34, ll. 2-8. Ms. Medine performed a Life Cycle Analysis of greenhouse gas emissions using the model developed by U.S. Department of Energy's Nation Energy Technology Laboratory. *Id.* Att. ESM-8. That analysis suggests that extending the useful life of A.B. Brown's two coal units beyond 2024 and replacing them on or before 2034 with non-carbon emitting generation would result in less carbon emissions than retiring them in 2024 and replacing them with the 850 MW CCGT Vectren South proposes. *Id.*

(4) Risk

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. Under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient, and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. For example, as we discussed earlier, Vectren South replaced one arbitrary coding system (red, yellow, green) with another (zero, five, ten). We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing. Vectren South had updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.,* Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks and did nothing to consider the risk of future methane regulations or restrictions. *See* JI Ex. 2 at 43; Vicinus Rebuttal, Tr. p. D-45. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. In so doing, that metric was biased in favor of portfolios with surplus generation. Finally, Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased that analysis in favor of gas-fired generation.

Finally, as already stated, we are concerned that Vectren South failed to remedy several flaws in its analysis identified in the Final Director's Report on the 2016 IRP. As summarized by Mr. Vicinus' testimony, Vectren South declined to analyze portfolio performance based on two standard deviations, declined to use a cumulative probability chart to present the cost-risk trade-off, and declined to revise its approach to evaluating exposure to MISO capacity markets. Pet. Ex. 7 at 7, ll. 19-20.

In light of these concerns, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. Instead, the risk analysis depends on stale inputs, ignores known risks, and arbitrarily scores portfolios.

g. Ind. Code § 8-1-8.5-5(e)

Indiana Code § 8-1-8.5-5(e) applies because Vectren South proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. That section provides that before granting a certificate to the applicant, the Commission:

> (1) must, in addition to the findings required under subsection (b), find that:
>
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
>
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
>
> (2) shall also consider the following factors:
>
> (A) Reliability.
>
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The section further provides that the applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection. We address the elements of Ind. Code § 8-1-8.5-5(e) in turn below.

(1) Are the estimated costs of the proposed facility, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable?

Vectren South presented the testimony of Diane Fischer of B&V regarding the development of the CCGT project cost estimate. Ms. Fisher testified that the cost estimate is based on competitively bid pricing for procurement (which she described as equipment) and construction. She stated that engineering was not competitively bid because B&V's competitors would not provide B&V with engineering services bids. As explained below, the failure to competitively bid engineering estimates is a fatal flaw, because it is Vectren South's (not B&V's) responsibility to satisfy that element of proof. There is no evidence that Vectren South itself could not have solicited competitive engineering bids.

Ms. Fisher stated that B&V is fully capable of providing a reliable estimate for engineering contracts and its estimate is within the +/- 10% range of accuracy. Ms. Fisher testified that the EPC cost estimate for a 2 x 1 F-class project is $582 million with a +/- 10% degree of accuracy. Mr. Games provided the following table to explain how the $582 million EPC estimate factors into the total $781 million cost estimate. Pet .Ex. 4, p. 15.

Description	GE F.05 (F) 2x1
B&V EPC Estimate (2017$) (includes overhead & profit, contingency & escalation)	$582M
Owner's Cost/Allowance	$40M
Builder's Risk Insurance	$3M
Owner's Contingency	$41M
Study Costs	$14M
AFUDC	$96M
Escalation (owner's allowance and owner's contingency)	$5M
Total Vectren Estimate	**$781M**

In determining whether Vectren South has satisfied the statutory requirement at issue, we must determine whether Vectren South's cost estimate is, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. We cannot find that Vectren

South satisfied this requirement. While Vectren South, through its contractor B&V, provided testimony demonstrating that it competitively bid the procurement and construction portion of the project, it admitted that it did not competitively bid the engineering contract. The explanation for this failure, provided by B&V witness Fischer, is that it was not commercially practicable for B&V to competitively bid engineering contracts because B&V's own competitors were not going to supply estimates to B&V. We do not agree that this reasoning qualifies as commercial impracticability for *Vectren South* itself, as Petitioner, to obtain competitively bid engineering prices.

Commercial impracticability is a legal doctrine that excuses a party's performance of an obligation. The doctrine is commonly applied as a defense to a party's performance of a contract. A party to a contract may be relieved of its contractual obligation when an unforeseen event, beyond the party's control, makes the performance of the contract excessively burdensome, difficult, or expensive. In *John Hancock Life Ins. Co.,* the court noted that 'foreseeable' is different from 'conceivable' and "[i]f 'foreseeable' is equated with 'conceivable', nothing is unforeseeable." *Hoosier Energy Rural Elec. Co-op., Inc. v. John Hancock Life Ins. Co.*, 588 F. Supp. 2d 919, 932 (S. D. Ind. 2008). Permanent discharge of a party's obligation under the doctrine of commercial impracticability is possible when the party's performance is made impracticable "without his fault by the occurrence of an event the non-occurrence of which was a basic assumption on which the contract was made[.]" Restatement (Second) of Contracts, §261. When determining whether commercial impracticability should excuse a party from an obligation, courts evaluate the degree to which the party could have foreseen the event creating an obstacle for performance of the party's obligation. "The relevant inquiry is whether the risk of the occurrence of the contingency was so unusual or unforeseen and the consequences of the occurrence of the contingency so severe that to require performance is to grant the buyer an advantage he did not bargain for in the contract." *BRC Rubber & Plastics v. Cont'l Carbon Co.*, 949 F. Supp. 2d 862, 876 (N.D. Ind. 2013), citing *Waldinger Corp. v. Ashbrook-Simon-Hartley, Inc.*, 775 F. 2d 781, 786 (7th Cir. 1985).

When we apply this authority to the instant case, we cannot find that it was commercially impracticable for Vectren South to satisfy its statutory obligation to obtain a competitively bid engineering contract. Vectren South's excuse for not obtaining a competitively bid engineering contract (*i.e.*, that none of B&V's competitors would give competitive bids to B&V) in no way suggests that Vectren South was unable to foresee that competitors might refuse to give B&V competitive bids; nor has Vectren South made any demonstration that it would be unduly burdensome for Vectren South (or another Vectren South agent) to solicit competitive engineering bids in compliance with the statute. Vectren South was well aware of its statutory obligations when it hired B&V. Ms. Fischer testified that because B&V is an engineering firm, it is "fully capable of providing a reliable estimate for those contracts and our estimate is within the +/- 10% range." A failure to obtain competitive bids cannot be excused merely because the single bidder is "capable of providing a reasonable estimate" or because the single bidder's estimate is "within the +/- 10% range." Estimate reliability and accuracy are not the only considerations. Underlying the statute's requirement for competitive engineering bids is a concern that the utility select an engineering contract that is competitively priced so that ratepayers do not unnecessarily pay a premium. The inclusion of market based pricing is especially important here given the substantial cost of the proposed project and the significant portion of the total price that corresponds to engineering. This is especially true where there is no evidence that it would have been costly, burdensome, or impossible for Vectren South to obtain a competitive engineering bid. Based on the foregoing, we find that Vectren South has not met its statutory burden of demonstrating that the estimated project costs are the result of competitively bid engineering, procurement and construction contracts.

(2) If the applicant is an electricity supplier (as defined in Ind. Code § 8-1-37-6), did the applicant allow or will it allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available?

Since Vectren South is a public utility that was furnishing retail electric service to customers in Indiana on January 1, 2011, it qualifies as an "electricity supplier" as defined in Ind. Code § 8-1-37-6. Vectren South witness Games testified that Vectren South intends to solicit bids from three manufacturers of the F-class units upon approval of Vectren South's petition. Although not stated directly by witness Games, Vectren South implies that it will require binding bids that meet all of its technical, commercial or other specifications so as to enable ownership of the proposed facility to vest with Vectren South not later than the date on which the proposed facility becomes commercially available. In light of our findings above, however, this consideration is moot.

(3) Reliability Considerations

We are required to consider reliability in determining whether to grant Vectren South's request. Indeed, our own 2018 Annual Report to the Indiana General Assembly at page 5 states the Commission is "required by statute to be impartial and to make decisions in the public interest to ensure regulated utilities provide safe and reliable service at just and affordable rates." NERC defines reliability of the interconnected bulk power system in terms of: 1) the ability of the electric system to supply the electric power and energy requirements of consumers at all times; and 2) the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.

Vectren South's preferred portfolio reduces coal-fired generation and replaces it with natural gas-fired generation. As several witnesses noted, Vectren South's near total dependence on natural gas as compared to a more diverse fuel portfolio threatens reliability. Ultimately, for the same reasons we discuss with regard to fuel diversity, we conclude that while the use of natural gas-fired generation does not in and of itself threaten reliability, *over reliance* on any single fuel source is not consistent with the need to ensure continuous power supply and overall system stability. Accordingly, we find that Vectren South's proposal to supply 72% to 77% of its firm capacity with a single fuel source is not consistent with the mandate to maintain a reliable generation portfolio.

(4) Consideration of Vectren South's solicitation of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The Commission must next consider whether Vectren South solicited competitive bids to obtain purchased power capacity and energy from alternative suppliers. This is an important consideration for many reasons. First, because of the regulatory compact, a utility earns a return of and on prudently incurred investments. Absent this statutory requirement, a regulated utility would not likely make purchasing decisions driven by competitive pricing. Second, because a regulated utility earns the return of and on its investment, the utility has an incentive to "gold plate" investments because ratepayers fund them and the utility's shareholders enjoy higher returns on more expensive investments. In many ways, this statutory requirement injects an obligation for the utility to follow market signals for the benefit of ratepayers rather than making investments that benefit shareholders to the ratepayers' detriment.

With these considerations in mind, we evaluate whether Vectren South met the statutory requirement and engaged in a fair and reasonable competitive bidding process that was designed to identify competitively priced purchased power capacity and energy from alternative suppliers. After a review of the evidence, we conclude that Vectren South's RFP process was not unbiased, fair or reasonable because Vectren South's RFP was crafted to exclude potentially lower-cost and diverse alternatives and to favor Vectren South's self-build option. After a review of all the evidence, we conclude that Vectren South designed its RFP to reinforce the company's predetermined conclusion. As we further discuss below, this conclusion is supported by substantial evidence demonstrating that Vectren South's RFP was unreasonably narrow with regard to resource size; resource location; fuel source; ownership structure and suffered from a slanted bid evaluation process biased toward Vectren South's self-build option.

(A) The RFP Unreasonably Narrowed Resource Size – Vectren South's RFP was narrowly constructed to automatically exclude resources smaller than 600 MW. Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater diversity, flexibility, and cost-efficiencies than a large gas plant. Tr., p. B-25. A smaller resource or a combination of smaller resources could provide lower market risk exposure, increased optionality, and greater resource diversity. JI Ex. 2 at 46. But since Vectren South tailored its solicitation to exclude these alternatives, the record is devoid of evidence showing that Vectren South's preferred gas plant can compete with combinations of smaller resources outside the company's modeling, in the real world. Vectren South unilaterally decided that a combination of smaller resources would not suffice. We find this decision unreasonable and imprudent.

(B) The RFP Unreasonably Narrowed Resource Location - After limiting generator types and sizes for the RFP, Vectren South further restricted RFP responses to only large gas plants sited in MISO Zone 6. The company did not use the RFP to collect actual cost data on resources in areas immediately adjacent and deliverable to Vectren South's system, such as Illinois (MISO Zone 4) for example. JI Ex. 2, p. 46. Although the company justifies its refusal even to collect data on potential resources outside MISO Zone 6 by pointing to MISO local resource clearing requirements ("LCRs") and congestion costs, we find the reasoning flawed for two reasons.

First, we note that MISO's LCR for Zone 6 requires just 67% of Vectren South's generation to be sited in Indiana. Pet. Ex. 2 at 4; Tr. I-84. That percentage is calibrated to ensure system reliability, meaning MISO expects reliability to be adequately maintained so long as no more than roughly a third of generation is sited outside Zone 6. While that reliability requirement may fluctuate over time, it allows considerable room for reliance on generation outside Zone 6. Despite the fact that Vectren South's portfolio can include a significant percentage of resources sited outside Zone 6, Vectren South has planned its proposed portfolio to rely 100% on resources within Zone 6. Tr. at I-86. Vectren South characterizes that planning decision as assuming "zero risk" that it does not comply with the MISO LCRs going forward. Tr. at I-86. Zero risk, however, is imprudent and expensive given the facts. Here, as in most situations, zero risk planning is not likely to lead to an optimal or prudent result. Ultimately, we find that Vectren South unreasonably rejected without any analysis the possibility that a combination of resources including some sited immediately adjacent to its system could cost-effectively and reliably serve its customers.

Second, Vectren South's congestion analysis was unreasonably narrow. Vectren South's analysis does not support conclusions beyond the single question asked in that analysis: would congestion costs for a site roughly 150 miles off-system make a particular third-party build more expensive than Vectren South's self-build estimate. Tr., p. B-37 (confirming congestion analysis only considered one off-system generation site). This is far from supporting the claim that no off-system resource could possibly compete with a self-build at the Brown site because *one* off-system resource could not compete. Vectren South demonstrated the materiality of congestion costs associated with *one* off-system resource and made no investigation whatsoever of congestion costs beyond that one site. Vectren South has presented no evidence that it evaluated the availability of system-adjacent resources in MISO Zone 4 or the attendant congestion costs to deliver power from such a resource. For these reasons, we find that Vectren South unreasonably and narrowly designed its analysis to wholly exclude such resources, thereby protecting its preferred build from the threat of real-world competition.

(C) The RFP Unreasonably Limited Eligible Fuel Sources – Vectren South's RFP limited respondents to only gas-fired resource proposals. The evidence reveals that another Indiana utility, NIPSCO, recently conducted an all-resource RFP and reached a very different result than Vectren South based on evaluation of real-world market cost data. While Vectren South's heavily restricted RFP garnered few responses with virtually no diversity among them, NIPSCO recently received 90 bids totaling nearly 10 GW of capacity after issuing an all-resource RFP. JI Ex. 2, p. 47; JI-CX-14, NIPSCO 2018 IRP Update Mtg. Unlike Vectren South, NIPSCO allowed RFP responses from all technology types, included consideration of "smaller resources to offer their solution as a piece of the total need," expressed no preference for ownership over PPAs, and required deliverability to (but not siting in) MISO Zone 6. JI Ex. 2, at 46-47 (quoting JI-CX 13 NIPSCO IRP 2018 Update Mtg. Three). Upon incorporating the pricing from those many and varied RFP responses into its resource modeling, NIPSCO found renewable resources provided lower-cost, lower-risk solutions than a new gas plant. JI-CX 14, NIPSCO IRP 2018 Update Mtg. Four, 47. While we recognize that NIPSCO's system and needs are distinct, the evidence demonstrates the value of considering a broad range of fuel resources. Accordingly, we find that Vectren South's decision to limit RFP consideration to gas-fired resources was unreasonable.

(D) The RFP Evaluation Was Flawed to Favor Vectren South's Self-Build – The record shows that Vectren South did not submit a bid as part of the RFP process and therefore was not under the same time constraints as the other bidders. After ranking the eleven proposals from six different developers, B&McD identified a single finalist company. Only then did B&McD compare the finalist to Vectren South's self-build option. We agree with the evidence offered by Mr. Hayet that it was "highly unusual" that Vectren South did not submit its self-build proposal into the RFP at the beginning, but rather compared it only to other bids in the final selection process. The evidence also shows that the RFP bid evaluation process initially used two different capacity values for the calculations in the same spreadsheet, and later used three different capacity values in the final PROMOD NPV RFP evaluation. To derive fixed O&M costs, firm gas reservation costs, and production costs in the same bid, Vectren South used yet different capacity values, which casts doubt on the consistency and quality of Vectren South's RFP bid evaluation. ICC Ex. 2 p. 16. These facts are further evidence that the RFP process did not conform to the spirit of the statute that requires fair and reasonable evaluation of competitive RFPs for the benefit of ratepayers.

(E) The RFP Unreasonably Disfavored PPAs – Vectren South's RFP stated an explicit preference for Vectren South to purchase and own the physical generation facilities, meaning that bidders were strongly discouraged from submitting PPAs that could satisfy Vectren South's need through the purchase of power owned by a third party. We note this preference may well have had a chilling effect on bids that could have produced a lower cost solution for ratepayers. Vectren South further limited consideration to PPAs with more than a 20-year term. We find these restrictions unreasonable. We agree with the evidence presented suggesting that PPAs of a shorter, 10-15 year duration, can provide optionality that could provide more flexibility versus building the proposed CCGT that will be in service for decades and foreclose other options.

Ultimately, we find that taken in concert, these RFP limitations worked to ensure that Vectren South's preferred gas plant self-build would have as little competition as possible from outside bidders in the real marketplace, which is inconsistent with the statute. Vectren South narrowly tailored its solicitation to include only dispatchable resources in Zone 6, and then only analyzed congestion costs for one alternative site. This analysis thus guaranteed that Vectren South's self-build would emerge as the preferred alternative from the RFP: Vectren South constrained the analysis to evaluating only whether a large on-system gas plant, where there would be no congestion costs, would be less expensive than building essentially the same gas plant off-system, where there would be congestion costs. In effect, the process appears "designed and carried out with the intention of showing that [Vectren South's] self-build was not inferior to other new build locations" for a large gas plant in Zone 6. *Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 24 (IURC, May 14, 2014). The solicitation does nothing to collect market-based data on different generation types, sizes and combinations, or locations, effectively excluding other alternatives from competing against Vectren South's preferred self-build in the RFP process. The evidence is clear that Vectren South consistently had its proverbial "thumb on the scale" and did not ensure that its bidding process solicited the best, most competitive pricing to emerge to the benefit of ratepayers. For all of these reasons, we find that Vectren South failed to satisfy the requirement of Ind. Code § 8-1-8.5-5(e)(2)(B) to conduct a fair and reasonable competitive bidding process designed to identify, for the benefit of ratepayers, competitively priced purchased power capacity and energy from alternative suppliers.

h. Conclusions regarding CPCN for new CCGT

The complicated and inconsistent modeling and analytical steps Vectren South uses as support are at best inconclusive. It is unclear that continued operation of A.B. Brown units 1 or 2 after 2023 is impossible without an expensive scrubber replacement. But even assuming an expensive scrubber replacement, the long-term costs to customers represented as net present value are so close between the cases of (a) continuing to operate A.B. Brown units 1 & 2 and (b) retiring them and building an 850 MW CCGT, that they are within the margin of modeling uncertainty. Another delay case modeled by Mr. Hayet is also within the margin of modeling uncertainty. The case of re-fueling the existing boilers at A.B. Brown to burn natural gas, which the OUCC asked Vectren South to model, also appears worthy of more serious consideration than Vectren South has given it. Accordingly, we cannot conclude from the modeling evidence that Vectren South's proposed CPCN is preferable over several other alternatives. However, Vectren South's preferred CPCN plan will certainly have the highest up-front capital cost that could result in the heaviest rate impact on customers. The other alternatives all appear to have significantly lower capital costs and thus less potential for rate shock.

While Vectren South's preferred CPCN plan would diversify its base load generation from 100% coal to 70% natural gas and 30% coal, given Vectren South's size, we are concerned that Vectren South's plan seems too much "all eggs in one basket." Vectren South's current base load generation is spread among 5 units (none of which is more than 30% of the total) at 3 locations (none of which is more than 50% of the total). Vectren South's plan would concentrate 70% of its base load generation in a single unit at a single location.

Vectren South's plan will commit it for 30 years or more to having most of its generation come from a carbon emitting technology. Given the present uncertainties about the future of carbon emitting technologies in the U.S. and world economies, such a heavy long-term bet on natural gas presents material downside risk to its customers, should things not go as anticipated, either with respect to carbon emissions or natural gas prices and availability.

No one has a crystal ball that shows what alternatives for capacity may present as viable alternatives to natural gas generation in 2030, or 2040. But from the information available to us as regulators we do know that many people and companies are putting significant effort into finding less expensive ways to supply energy without emitting greenhouse gasses. So, without clear evidence to the contrary (which the company's modeling evidence does not provide), we are reluctant to approve Vectren South having most of its generation capacity tied to a greenhouse emitting fuel through potentially 2060 or even later. We support Vectren South's desire to diversify its generation portfolio. But based on the evidence we conclude Vectren South's proposed plan in fact reduces the diversity and flexibility of its generation portfolio and introduces unacceptable future risks.

For all these reasons we will deny Vectren South's request for a CPCN to construct a new CCGT generator and all associated relief requested by the company. We note that Vectren South's 2019 IRP stakeholder process is not concluded. Vectren South should take seriously the Commission's findings regarding the shortfalls in the 2016 IRP as well as stakeholder feedback in its 2019 IRP.

B. CPCN for Culley compliance projects and related relief

We move next to Vectren South's request for approval of the Culley 3 compliance project. Witness Lauren Aguilar of the OUCC recommended that we deny Vectren South a CPCN for the Culley 3 compliance projects pursuant to Ind. Code ch. 8-1-8.4, *et seq*. Under the federal mandate statute (Ind. Code §§ 8-1-8.4-5, -6, and -7), Vectren South has requested several projects for environmental remediation at Culley 3: costs for closure of the inactive Culley West pond in order to build a new process and storm water pond on the same location; spray dry evaporator; and a submerged chain conveyor for ash transport. Pub. Ex. 1, p. 26. However, to recover costs under the federal mandate statute, a utility must show that the project is required under specified federal statutes: the Clean Air Act, the Water Pollution Control Act, Resource Conservation and Recovery Act, or the Toxic Substances Control Act. Pub. Ex. 1, pp. 26-27.

Unfortunately for Vectren, its requested Culley West pond closure costs do not meet the federal mandate statute's requirements. Vectren South witness Angila Retherford testified that the closure was necessary to "reuse the space to construct facilities necessary to comply with the ELG rule." Direct Testimony of Angila Retherford, p. 18, ll. 19-20. In addition, closure of the pond occurred when Vectren South stopped sending ash before October 2015, which was prior to the effective date the CCR rule took effect. Pub. Ex. 1, p. 28, ll. 1-13.

Before the CCR rule came into effect, Vectren South had incurred and collected costs for ash disposal in its rates, as have all coal-burning utilities. Pub. Ex. 1, p. 28. While the CCR rule may have sped up the need for closure, Vectren South has not shown evidence regarding incremental costs that are in excess of pond closure costs previously included in rates. *Id.* As pointed out by Ms. Aguilar, "[t]hree other Indiana utilities are not tracking pond closure costs as Federally-Mandated CCR Projects." *Id.* pp. 28-29. In the absence of complete evidence supporting pond closure costs that meet statutory requirements, we will not approve Vectren South's request. Vectren South is obligated to show "[a]lternative plans that demonstrate that the compliance project is reasonable and necessary." Ind. Code § 8-1-8.4-6(b). Vectren South has not done so, and in the absence of complete information – including the pond closure costs Vectren South has collected in rates and compliance alternatives– we will not approve these projects.

C. Recovery of deferred costs authorized in Cause No. 44446

Vectren South has requested authority to recover costs incurred for MATS compliance, as previously approved in Cause No. 44446, through an environmental tracker denominated the ECA. Mr. Blakley and Ms. Aguilar reviewed Vectren South's request and had no objection to the requested recovery through the ECA. As with all environmental trackers, we anticipate that we and the OUCC will review Vectren South's filings to determine compliance with the Cause No. 44446 orders.

We therefore find that Vectren South's request for an ECA to recover MATS costs as authorized in Cause No. 44446 is approved.

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

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is denied.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA shall be and hereby is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA shall be and hereby is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED:

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

____

Mary M. Becerra
Secretary to the Commission