FILED
July 2, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE CITY OF RICHMOND, INDIANA, BY AND THROUGH ITS MUNICIPAL ELECTRIC UTILITY, RICHMOND POWER AND LIGHT, FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES FOR ELECTRIC SERVICE AND APPROVAL OF AN AMENDMENT TO ITS ENERGY COST ADJUSTMENT PROCEDURES	))))))))	**CAUSE NO. 45361**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 5

TESTIMONY OF OUCC WITNESS

CALEB R. LOVEMAN

JULY 2, 2020

Respectfully submitted,

Tiffany Murray
Attorney No. 28916-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS CALEB R. LOVEMAN
CAUSE NO. 45361
RICHMOND POWER & LIGHT

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Caleb R. Loveman, and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

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

A: I am employed as a Utility Analyst in the Indiana Office of Utility Consumer Counselor's ("OUCC") Electric Division. A summary of my educational background and experience is included in Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide analyses and make recommendations on multiple proposals Richmond Power & Light ("RP&L" or "Petitioner") made in its case-in-chief. Specifically, I address RP&L's proposed: (1) labor expenses; (2) employee benefits expense; (3) Federal Insurance Contributions Act ("FICA") tax expense; (4) environmental remediation expense for the Coal Combustion Residual ("CCR") Pond at White Water Valley Station ("WWVS"); (5) remediation expense removal; and (6) dollar amount and amortization period for the WWVS demolition. Ultimately, I recommend:

(1) Labor, Employee benefits, and FICA tax expenses be adjusted to reflect the fixed, known, and measurable costs;

(2) An eight-year amortization period for the WWVS CCR Pond's environmental remediation liability, based on OUCC witness Lauren M. Aguilar's recommendation;

(3) A reduction to the total cost of, and a 10-year amortization period for, the WWVS demolition; and

(4) Acceptance of Petitioner's adjustment to remove test year remediation expense.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I reviewed RP&L's petition, testimony and exhibits, workpapers, Minimum Standard Filing Requirements ("MSFR"), and responses to OUCC discovery. I also reviewed RP&L's prior rate case, Cause No. 42713, including the settlement agreement between the OUCC and RP&L, and the Indiana Utility Regulatory Commission's ("Commission" or "IURC") Final Order dated February 9, 2005. I also participated in conference calls with RP&L representatives to discuss its case-in-chief.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts RP&L proposes does not indicate my approval of those adjustments or amounts, but rather the scope of my testimony is limited to the specific items addressed herein.

II. LABOR, EMPLOYEE BENEFITS, AND FICA TAX EXPENSE ADJUSTMENTS

Q: Is RP&L proposing an adjustment to its test year labor, FICA tax, and employee benefits expenses?

A: Yes. RP&L proposes increasing its test year labor expense by $254,161[1] (4.63%),[2] its test year employee benefits expense by $112,768[3] (3.00%),[4] and its test year FICA tax expense by $53,389[5] (11.90%).[6]

Q: Please explain how RP&L calculated its adjustments to labor expense, employee benefits expense, and FICA tax expenses.

A: According to RP&L witness Laurie Tomczyk, labor expense adjustments were represented by projected expenses for the last quarter of 2019 and the first three quarters of 2020.[7] Based on my review of Ms. Tomczyk's workpapers and the information provided through the OUCC's virtual audit, I determined RP&L's labor expense adjustment was based on both actual and budgeted/projected expenses. The 2019 portion includes actual expenses and the 2020 portion includes budgeted/projected expenses. RP&L's testimony does not explain in detail how it calculated adjustments to the FICA tax and employee benefits expenses. However, after reviewing the Excel spreadsheet workpapers, specifically, LAT WP 8 Labor and Benefits Adj, supporting Ms. Tomczyk's Attachment LAT-2, I was able to determine these adjustments were done in a similar but different fashion than the labor expense adjustment. RP&L's proposed FICA tax expense and employee benefits expense percentage increases were

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[1] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2 p. 16, line 108, column G; and OUCC Attachment CRL-7, RP&L Response to DR 17.1.
[2] See OUCC Attachment CRL-1, p. 1, line 1.
[3] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2 p. 16, line 120, column G.
[4] See OUCC Attachment CRL-1, p. 1, line 2.
[5] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2 p. 16, column G.
[6] See OUCC Attachment CRL-1, p. 1, line 3.
[7] Direct Testimony of Laurie A. Tomczyk, p. 17, lines 21-23.

calculated by using a percentage based on the labor expense for each employee benefit and the FICA tax. The employee benefits expense adjustment percentage is calculated by taking 25% of the 2019 test year employee benefits expenses and dividing that amount by the 2019 test year labor expense. This resulting amount is then added to 75% of the 2020 budgeted employee benefits expenses divided by the 2020 budgeted labor expense. RP&L completed the same calculation for the FICA tax expense adjustment percentage. RP&L then multiplied the various percentages by the labor expense to arrive at the pro-forma amounts for the employee benefits and FICA tax expense adjustments.

Q: Do you have concerns with the underlying 2019 test year dollar amounts RP&L used in calculating its proposed adjustments to labor, FICA tax, and employee benefits expenses?

A: In part. I disagree with the dollar amounts RP&L used in calculating its labor and employee benefits expenses adjustments. I do not have concerns with the dollar amount RP&L used in calculating its FICA tax expense adjustment. In its case-in-chief, RP&L provided no support for the 2020 budgeted portion of its labor, employee benefits, and FICA tax expenses. In response to OUCC DR 17.2, RP&L did not explain how it developed the 2020 labor expense budget, indicating the employee benefits expense is typically calculated at 40% of hourly pay and the FICA tax expense is calculated at standard employer contribution levels.[8] These amounts were hard-coded into the various workpapers and source documents RP&L cited.

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[8] *See* OUCC Attachment CRL-7, RP&L Response to DR 17.2.

Additionally, according to RP&L witness Randall W. Baker, RP&L's employee count dropped from 151 to 95[9] since RP&L's last rate case in 2004 (Cause No. 42713). Further, in response to OUCC DR 17.2, RP&L specified the employee count dropped from 151 to 95-97 over the past 20 years, and the planned hires for 2020 are replacements for workers who are retiring/retired or have passed away.[10] RP&L indicates its employee count decreased over the past several years, with any new hires replacing vacant, or soon to be vacant, positions. Therefore, no increase in labor expense is warranted.

Q: What changes do you recommend to RP&L's 2019 test year labor expense?

A: RP&L included $94,245 of labor expense related to its affiliated company Parallax (Account No. 92015, Salaries-Telecomm) in its test year expense,[11] which I recommend be removed. In response to OUCC DR 9.8, RP&L indicated this is the account Parallax employees' salaries are "charged" when payroll is processed. Parallax then reimburses RP&L for these salaries on a monthly basis. The account balance remaining is a result of a timing issue. RP&L agreed to remove this amount from its calculation.[12] Therefore, I recommend $94,245 related to labor for Parallax Systems be removed from the test year labor expense.

Q: What changes do you recommend to RP&L's 2019 test year employee benefits expense adjustment?

A: RP&L included several small expenses in its employee benefits expense adjustment, which I recommend be removed. These expenses, which were listed in RP&L's 2018

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[9] Direct Testimony of Randall W. Baker, p. 7, lines 15-18.
[10] *See* OUCC Attachment CRL-7, RP&L Response to DR 17.2, a.
[11] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2 p. 15, line 63, column D.
[12] *See* OUCC Attachment CRL-7, RP&L Response to DR 9.8.

and 2019 general ledgers in Account No. 92600, Empl Benefits-General, include various donations to organizations, retirement gifts given to RP&L employees, and various credit card charges including donations, retirement/celebration gifts, perfect attendance awards, health fairs, etc. totaling $2,582.[13] RP&L stated in response to OUCC DR 13.5:

> RP&L does not consider these expenses to be an employee benefit. Richmond's Municipal Code § 52.07(h) provides that RP&L is "authorized to engage in activities and expenditures of a reasonable nature which will promote good relations with its employees, including but limited to the issuance of award plaques, the sending of flowers to employees and their families as occasions warrant, and activities of a similar nature." This Ordinance was adopted pursuant to Richmond's home rule authority to under IC 36-1-3 provide for the promotion of city business and good relations with the community and its employees. The State Board of Accounts has recognized that as long as there is an authorizing ordinance, the expense amounts are not excessive, and are properly documented and approved under normal municipal procedures for claims, they are a proper use of public funds. Please see page 5 of the SBOA's December 2015 Bulletin on the Promotion of City and Town Business: https://www.in.gov/sboa/files/ctb2015_012.pdf.[14]

Even though Richmond's Municipal Code allows RP&L to make expenditures that are reasonable and not excessive in nature, ratepayers should not pay for these types of discretionary costs. These costs should be paid for by RP&L. Therefore, I made an adjustment to remove these costs from pro-forma test year expense.

Q: RP&L's pro-forma labor expense adjustment reflects a 4.63% increase. Do you have concerns with this percentage increase?

A: Yes. RP&L increased its test year labor expense to $5,744,605,[15] which reflects a 4.63% increase. As indicated previously in my testimony, RP&L's employee count has

[13] OUCC Attachment CRL-7, RP&L Response to DR 13.4.
[14] *Id.* RP&L Response to DR 13.5.
[15] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2, p.16, line 108.

decreased, with any new hires replacing vacant, or soon to be vacant, positions. RP&L has not provided evidence demonstrating an increase of 4.63% in labor expenses is necessary. Additionally, in response to OUCC Audit Request Set No. 18, RP&L provided its contract with the International Brotherhood of Electrical Workers, AFL-CIO Local 1395 ("IBEW"). According to pages 60 - 69 of the IBEW contract, for each listed position, workers will receive an annual 3% salary increase.[16]

Q: What percentage increase do you recommend be applied to labor, employee benefits and FICA tax expenses?

A: Consistent with the IBEW contract, I recommend a 3% increase to test year labor expense, because it is a fixed, known, and measurable amount. Using the IBEW contracted 3% annual increase amount reduces RP&L's proposed labor expense by $186,520,[17] resulting in pro-forma test year labor expense of $5,558,084.[18] In addition to this adjustment, I recommend the employee benefits and FICA tax expenses be adjusted to $3,874,717[19] and $462,150,[20] respectively, to reflect the 3% increase in my labor expense adjustment. These adjustments decrease RP&L's proposed employee benefits expense by $2,495[21] and FICA tax expense by $39,928.[22]

Q: How did you calculate the employee benefits expense adjustment?

A: First, I removed several small expenses from the employee benefits expense related to various donations, retirement gifts, etc., as previously discussed in my testimony. Then, I calculated the percentage of test year employee benefits by dividing test year

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[16] *See* OUCC Attachment CRL-5.
[17] *See* OUCC Attachment CRL-2, p. 1, line 7.
[18] *Id.* p. 1, line 5.
[19] *Id.* p. 2, line 13.
[20] *Id.* p. 3, line 3.
[21] *Id.* p. 2, line 15.
[22] *Id.* p. 3, line 4.

employee benefits by test year labor expense, as shown in my Attachment CRL-2, page 2. Next, I multiplied pro-forma proposed labor expense by the test year employee benefit percentage to derive the pro-forma proposed employee benefit amount provided above.

Q: How did you calculate the FICA tax expense adjustment?

A: I calculated the percentage of the test year FICA tax by dividing test year FICA tax by test year labor expense, as show in my Attachment CRL-2, page 3. Next, I multiplied pro-forma proposed labor expense by the test year FICA tax percentage to derive the pro-forma proposed FICA tax amount provided above.

III. <u>CCR AMORTIZATION AND EXPENSE</u>

Q: Has RP&L requested authority to recover through rates the liability related to closing WWVS's CCR pond?

A: Yes. According to Ms. Tomczyk, RP&L proposes to include $2,680,000 as part of its revenue requirement to close the CCR pond. This amount is based on an estimated cost of $12,374,806 in 2019 dollars, which was provided by an engineering firm contracted by RP&L. RP&L then escalated this amount to 2025 dollars based on a 2% annual inflation rate resulting in a total $13,401,105,[23] which RP&L proposes to amortize over a five-year period.[24]

Q: Do you have any issues with the calculation proposed by RP&L to arrive at the total CCR pond environmental remediation amount?

A: No. I agree with Petitioner's proposed calculation. However, I disagree with the amortization period proposed by RP&L.

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[23] Direct Testimony of Laurie A. Tomczyk, Attachment LAT-2, p.11.
[24] Direct Testimony of Laurie A. Tomczyk, p. 19, lines 17-23.

Q: Over what period do you recommend CCR pond environmental remediation costs be amortized?

A: As indicated by Ms. Aguilar, the final date, with extensions, for RP&L to have the CCR pond cap in place is 2028. Therefore, I recommend $1,811,802 in CCR pond environmental remediation costs be amortized annually over an eight-year period. This amount is based on a 2028 future value of the $12,374,806 in 2019 dollars, with a 2% yearly inflation rate amortized over eight years. This is a decrease of $868,198[25] from the test year amount RP&L proposes.

Q: Do you have any other recommendations regarding CCR pond environmental remediation costs?

A: Yes. I recommend the Commission require RP&L to deposit the annual amortization amounts for the CCR pond environmental remediation into a restricted cash reserve fund to ensure these funds will only be used for the CCR pond environmental remediation. I also recommend RP&L deposit these funds into an interest-bearing account. In addition, I agree with RP&L's adjustment to remove $631,877 of remediation expense from the revenue requirement.[26]

Q: Has the Commission previously approved using a restricted fund?

A: Yes. In *City of East Chicago*, Cause No. 44826, Final Order issued April 26, 2017, the Commission stated:

> In order to address some of the concerns raised by the Industrial Group at the hearing concerning the lack of detail for the Subsidization Program, we have included a reporting requirement for the $3.1 million funding, in addition to **a requirement that the funding be placed in a restricted account to be used solely for the Subsidization Program** [Emphasis added].[27]

[25] *See* OUCC Attachment CRL-3, p. 1, line 7.
[26] Direct Testimony of Laurie A. Tomczyk, p. 22, lines 12-18.
[27] *Petition of the City of E. Chicago,* Cause No. 44826, Final Order, p. 20 (Ind. Util. Regulatory Comm'n Apr. 26, 2017).

Similar to the Commission's Cause No. 44826 Order, I recommend the annual CCR pond environmental remediation amortization amounts RP&L requests be placed into a restricted account to be used solely for environmental remediation expenses related to the CCR pond closure.

IV. WWVS DECOMMISSIONING

Q: What is your understanding of WWVS's ownership and operation?

A: According to Mr. Baker, RP&L retains ownership of WWVS, but Indiana Municipal Power Agency ("IMPA") operates WWVS pursuant to an Amended and Restated Capacity Purchase Agreement ("Capacity Agreement").[28] Ultimately, RP&L is responsible for the costs related to decommissioning or retiring WWVS. However, pursuant to the Capacity Agreement, IMPA is required to pay a decommissioning payment of $500 multiplied by the number of months comprising the term of the Capacity Agreement within 90 days of the termination of the agreement.[29] IMPA will also be responsible for any environmental claims during the Capacity Agreement's term.[30]

Q: What does RP&L propose regarding WWVS's decommissioning?

A: Ms. Tomczyk testified that IMPA's 2017 Integrated Resource Plan ("IRP") assumes retiring the WWVS at the end of 2025.[31] Based on the projected retirement date, Ms. Tomczyk proposes $1,843,964 be deposited annually through 2025 into a decommissioning reserve fund for the WWVS.[32] Ms. Tomczyk arrived at this amount

[28] Direct Testimony of Randall W. Baker, p. 14, lines 18-19.
[29] *Id.* p. 17, lines 4-9.
[30] *Id.* lines 10-12.
[31] Direct Testimony of Laurie A. Tomczyk, p. 31, lines 18-19.
[32] *Id.* lines 21-23.

using industry data related to coal plant decommissioning, based on other utility rate case filings and public utility commission ("PUC") orders. Ms. Tomczyk adjusted the researched amounts to 2019 dollars to arrive at an average cost of $76.47 per kWh for coal plant decommissioning. Ms. Tomczyk then inflated the estimate to 2025 dollars and divided this amount by five years to arrive at the total annual deposit amount.[33] As shown in Ms. Tomczyk's Attachment LAT-2, page 44, and in response to OUCC DR 7.1, Ms. Tomczyk used the Handy Whitman Index to adjust the WWVS decommissioning costs to 2019 and 2025 dollars.[34]

Q: Do you have concerns with the annual deposit amount RP&L proposes to include in a decommissioning reserve fund for the WWVS?

A: Yes. Even though the amount RP&L proposes to deposit annually does not directly affect the proposed revenue requirement, there are two issues with RP&L's proposed decommissioning reserve fund that need to be addressed. First, it is unclear when the WWVS will actually retire. Second, based on my analysis, RP&L overstated the adjusted 2019-dollar and 2025-dollar amounts explained above.

Q: What is your concern with the WWVS retirement date?

A: As Mr. Baker states, "WWVS's retirement date is not definitive at this time, it will most likely occur in the next five to ten years."[35] Even though IMPA's 2017 IRP projects the WWVS retiring at the end of 2025, IMPA's IRP cannot be completely relied on, as IMPA's IRP is a 20-year projection updated every three years and is subject to change. For example, IMPA's 2015 IRP, attached as Attachment CRL-6,

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[33] *Id.* lines 5-23.
[34] *See* OUCC Attachment CRL-7, RP&L Response to DR 7.1.
[35] Direct Testimony of Randall W. Baker, p. 16, lines 15-19.

projected a retirement date for WWVS as of the end of 2022.[36] This is three years earlier than the date indicated in IMPA's most recent 2017 IRP. Furthermore, in response to OUCC DR 9.3, RP&L states, "RP&L has not conducted a study on decommissioning costs which would likely include an estimate of the timing of the decommissioning process."[37] Based on Mr. Baker's statement, IMPA's 2015 and 2017 IRPs, and RP&L's response to OUCC DR 9.3, WWVS's retirement date is not fixed, known, and measurable, but is projected to happen within the next 10 years. Therefore, I recommend an amortization period of 10 years to 2030, which is the final year of Mr. Baker's estimate.

Q: What are your concerns with the adjusted 2019- and 2025-dollar amounts RP&L proposes?

A: Both the adjusted 2019-dollar amount for the per kWh costs and the inflated 2025-dollar amount for decommissioning are overstated. Ms. Tomczyk uses the Handy Whitman Index to arrive at her proposed 2019- and 2025-dollar adjustments. This publication is not a publicly available document and requires a subscription to access its contents. The inflation rates provided by the Handy Whitman Index are greater than inflation rates provided by the U.S. Bureau of Labor Statistics and Ms. Tomczyk provides no support or explanation for the use of the Handy Whitman Index over other sources. Therefore, because inflation rates provided by the U.S. Bureau of Labor Statistics are publicly available, I recommend using its inflation rates to arrive at the adjusted 2019 per kWh cost. I also recommend an annual 2% inflation rate, similar to the rate RP&L utilized in its CCR pond cap in place calculation, to arrive at 2030

[36] *See* OUCC Attachment CRL-6, p. 16.
[37] *See* OUCC Attachment CRL-7, RP&L Response to DR 9.3.

dollars (using a 10-year amortization period). Based on these recommendations, I calculate an average cost of $72.93[38] per kWh in 2019 dollars for decommissioning. I then inflate this amount to 2030 dollars and calculate $8,350,870 in total decommissioning costs.[39] This results in an $835,087[40] annual amortization amount based on a ten-year amortization period, which is $1,008,877[41] lower than what RP&L proposes.

Q: Do you have any other recommendations regarding the annual amortization amount to be deposited in RP&L's proposed decommissioning reserve fund?

A: Yes. Similar to my recommendation in Section III of my testimony, I recommend the Commission require RP&L deposit the annual amortization amounts into a restricted cash reserve fund to ensure these funds will only be used for the decommissioning of the WWVS. I also recommend RP&L deposit these funds into an interest-bearing account.

V. RECOMMENDATIONS

Q: What do you recommend?

A: Based on my analysis described above, I recommend the following:

1) RP&L's pro-forma labor expense be adjusted to $5,558,084.
2) RP&L's pro-forma employee benefits expense be adjusted to $3,874,717.
3) RP&L's pro-forma FICA tax expense be adjusted to $462,150.
4) For RP&L's CCR pond environmental remediation:

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[38] *See* OUCC Attachment CRL-4, p. 1, line 6.
[39] *Id.* line 12.
[40] *Id.* line 13.
[41] *Id.* line 15.

a. RP&L's CCR pond environmental remediation liability be amortized over an eight-year period at an annual amount of $1,811,802, with the annual amount deposited into a restricted reserve fund and into an interest-bearing account; and

b. RP&L's test year CCR pond environmental remediation expense of $631,877 be removed from the test year.

5) RP&L amortize estimated decommissioning costs for the WWVS over a 10-year period at an annual amount of $835,087, and the annual amount be deposited into a restricted reserve fund and into an interest-bearing account.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A – Qualifications of Caleb R. Loveman

Q: Please summarize your educational background and experiences.

A: I graduated from Franklin University in 2015 with a Bachelor of Science in Accounting. From 2016 to 2019, I owned and operated an E-commerce business. In this role I was responsible for all the accounting, finance, and tax related functions of the business. During this time, I also worked as a Staff Accountant for Legacy Administration Services, LLC and as a Financial Analyst for Cummins, Inc. I began my career with the OUCC in July 2019 as a Utility Analyst in the Electric Division. I review Indiana utilities’ requests for regulatory relief filed with the Commission. I also prepare and present testimony based on my analyses and make recommendations to the Commission on behalf of Indiana utility consumers. Since joining the OUCC, I have attended “The Basics” Practical Regulatory Training for the Electric Industry, sponsored by the National Association of Regulatory Utility Commissioners (“NARUC”) and the New Mexico State University Center for Public Utilities, in Albuquerque, New Mexico. I have also attended the 2019 Indiana Energy Association (“IEA”) Energy Conference and the 2019 Indiana Energy Conference presented by the Indiana Industrial Energy Consumers, Inc. (“INDIEC”).

Q: Have you previously filed testimony in other Commission proceedings?

A: Yes.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Caleb R. Loveman

Caleb R. Loveman
Utility Analyst I
Indiana Office of Utility Consumer Counsel

Cause No. 45361
Richmond Power & Light

Date: July 2, 2020

Richmond Power & Light
Cause No. 45361
RP&L Proposed Adjustments; Expense No.'s 2, 6, and 9

Line No.	Expense	Proposed Test Year	Adjustments	Adjusted Test Year	Percentage Increase
1	Labor Expense; Expense Adjustment No. 2	$ 5,490,443	$ 254,161	$ 5,744,605	4.63%
2	Employee Benefits Expense; Expense Adjustment No. 6	3,764,443	112,768	3,877,212	3.00%
3	FICA Tax Expense; Expense Adjustment No. 9	448,690	53,389	502,078	11.90%

Richmond Power & Light
Cause No. 45361
Adjustment to RP&L Expense Adjustment No. 2

Line No.	Description	Revenue Requirement
1	Test Year Labor Expense	$ 5,490,443
2	Removal of Account No. 92015	(94,245)
3	Total Test Year Labor Expense	$ 5,396,198
4	OUCC Recommended Annual Salary Percentage Increase	3.00%
5	OUCC Proposed Adjusted Test Year Labor Expense	$ 5,558,084
6	RP&L Proposed Adjusted Test Year Labor Expense	5,744,605
7	OUCC Increase/(Decrease) from RP&L Proposed Amount	$ (186,520)

Richmond Power & Light
Cause No. 45361
Adjustment to RP&L Expense Adjustment No. 6

Line No.	Description	Test Year	Percentage of Test Year Labor Expense	Adjusted Test Year Revenue Requirement
1	Labor Expense	$ 5,396,198		$ 5,558,084
2	Account No. 92600-Empl Benefits-General	26,785		
3	Less: Various Donations, Retirement Gifts, Etc.	(2,582)		
4	Total	24,203	0.45%	24,929
5	Account No. 92610-Empl Benefits-Pension	2,192,884	40.64%	2,258,670
6	Account No. 92615-Employee Benefit - Defined Contribution Plan	79,585	1.47%	81,972
7	Account No. 92620-Empl Benefits-Health Ins	1,403,026	26.00%	1,445,117
8	Account No. 92621-Empl Benefits-Life Ins	11,468	0.21%	11,812
9	Account No. 92622-Empl Benefits-Disability Ins	14,161	0.26%	14,585
10	Account No. 92630-Empl Benefits-Recreation	-	-	-
11	Account No. 92640-Empl Benefits-Educat Assist	1,908	0.04%	1,965
12	Account No. 92695-Vacation Earned	34,628	0.64%	35,666
13	OUCC Proposed Benefits Expense Adjustment	$ 3,761,861	69.71%	$ 3,874,717
14	RP&L Proposed Benefits Expense Adjustment			3,877,212
15	OUCC Increase/(Decrease) from RP&L Proposed Amount			$ (2,495)
16	OUCC Proposed Percentage Increase from Test Year			3.00%

Richmond Power & Light
Cause No. 45361
Adjustment to RP&L Expense Adjustment No. 9

Line No.	Description	Test Year	Percentage of Test Year Labor Expense	Adjusted Test Year Revenue Requirement
1	Labor Expense	$ 5,396,198		$ 5,558,084
2	Account No. 40812-Tax Exp-Fica	$ 448,690	8.31%	
3	OUCC Proposed FICA Tax Expense			$ 462,150
4	RP&L Proposed FICA Tax Expense			502,078
4	OUCC Increase/(Decrease) from RP&L Proposed Amount			$ (39,928)
6	OUCC Proposed Percentage Increase from Test Year			3.00%

Richmond Power & Light
Cause No. 45361
Adjustment to RP&L Expense Adjustment No. 13

Line No.	Description	Revenue Requirement
1	Environmental Remediation Liability 2019$	$ 12,370,846
2	Amortization Period in Years	8
3	Annual Inflation Rate	2%
4	Amortization Balance in 2028$	14,494,418
5	OUCC Proposed Annual Amortization Expense	$ 1,811,802
6	RP&L Proposed Annual Amortization Expense	2,680,000
7	OUCC Increase/(Decrease) from RP&L Proposed Amount	$ (868,198)

Richmond Power & Light
Cause No. 45361
WWVS Decommissioning

Line No.	Comparable Plants Presented by RP&L	Estimate Year	Dismantle Cost ($/kW)	Inflation Adjustment to 2019 $ U.S. Bureau of Labor Statistics	2019 Inflation Adjusted ($/kW)
1	Cayuga Station (Duke)	2018	$ 60.55	1.81%	$ 61.65
2	Fayette 1&2 (AE)	2015	38.45	7.86%	41.47
3	Xcel Energy (PSCo)	2013	77.00	9.74%	84.50
4	Deely (CPS)	2012	119.00	11.35%	132.51
5	Survey of PUC Cases	2012	40.00	11.35%	44.54
6	Average				$ 72.93

Line No.	Estimated WWVS Dismantlement Cost Description	Estimated Dismantlement Cost
7	Dismantlement Cost 2019 $/kW	$ 72.93
8	WWVS Total Name Plate Capacity kW	93,928
9	Estimated Dismantlement Cost 2019 $	$ 6,850,622
10	Annual Inflation Adjustment to 2030 $	2%
11	Amortization Period Years	10
12	Estimated Dismantlement Cost 2030 $	$ 8,350,870
13	OUCC Recommended Annual Decommissioning Fund Deposit	$ 835,087
14	RP&L Proposed Annual Decommissioning Fund Deposit	1,843,964
15	OUCC Increase/(Decrease) from RP&L Proposed Amount	$ (1,008,877)

AGREEMENT

BETWEEN

RICHMOND POWER AND LIGHT

AND

INTERNATIONAL BROTHERHOOD

OF ELECTRICAL WORKERS, AFL-CIO

LOCAL 1395

EFFECTIVE OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2022

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AGREEMENT

THIS AGREEMENT is made and entered into this 1st day of October, 2019, by and between Local 1395, International Brotherhood of Electrical Workers, AFL-CIO (hereinafter referred to as the "Union") and the Common Council of the City of Richmond, Indiana, and their successors.

ARTICLE 1

UNION RECOGNITION

Section 1. Recognition. The Common Council, pursuant to an election agreement dated June 4, 1975, recognizes the Union as the exclusive collective bargaining representative of:

> All employees of Richmond Power and Light (hereinafter referred to as the "Utility") in the Meter Department, Storeroom, General Office, Engineering Department, Line Department, Garage Mechanic "A", Garage Mechanic "B", Janitors and Maintenance Electrician, Energy Services Department, but excluding, all other employees, supervisors, guards, confidential employees and professional engineers.

"Employee" as used herein shall mean only employees within the above-described bargaining unit. If the Employer ever re-establishes Whitewater, the Utility will recognize IBEW Local 1395 as the exclusive collective bargaining representative of the employees.

Section 2. Students as Temporary Employees. The Utility may employ students as temporary summer employees and such temporary summer student employees shall not be within the bargaining unit and shall not be covered by or have the benefit of any of the terms of this Agreement, provided no such temporary summer student employees may be employed while bargaining unit employees are on layoff.

Section 3. Dues Checkoff/Initiation Fee. Richmond Power and Light shall deduct each month from the first two pays of each employee covered by this Agreement all dues and/or initiation fees of the Union and pay such amounts deducted to the Union, provided that the Union presents to Richmond Power and Light a proper authorization conforming to law signed by the employee.

Section 4. Deduction of Voluntary C.O.P.E. Contributions. The Utility agrees to make payroll deductions, as authorized by its employees, for the purpose of making contributions to COPE. Authorizations for deduction must be on a form which complies with all applicable state and federal laws. An employee who revokes his or her authorization may not authorize deductions again for six months. The Union agrees to indemnify and hold harmless the Utility from any and all liabilities resulting from this section.

ARTICLE 2

NO DISCRIMINATION

Neither the Utility nor the Union will discriminate in violation of state or federal law against any employee on the basis of race, color, religion, sex, national origin, or age or against a qualified individual with a disability because of that individual's disability.

ARTICLE 3

MANAGEMENT

Section 1. Management Rights. The management of the Utility's operations and direction of employees, including but not limited to the right to employ, promote, demote, train, transfer, lay off, discipline, suspend, or discharge for cause, to determine an employee's ability to perform the work required, to determine reasonable job content, to assign work and the number of hours to be worked, to increase and decrease the working force, to establish methods and procedures and job standards, to discontinue operations in whole or in part, to use improved methods or equipment, to determine sources and amounts of supply, to schedule the production and maintenance, to determine the number and location or relocation of plants and facilities, and to make reasonable rules and regulations in connection with the Utility's operations and the conduct and duties of its employees as are deemed advisable is vested solely and exclusively in the Utility, subject only to such limitations as are contained in this Agreement.

Section 2. Subcontracting. The Utility may subcontract work other than work normally and regularly performed by members of the bargaining unit. It may subcontract work normally and regularly performed by members of the bargaining unit (1) in accordance with its past practice (provided no bargaining unit employees are laid off as a result), or (2) where such subcontracting does not result in the layoff of bargaining unit employees or prolong the layoff of qualified bargaining unit employees who normally and regularly perform the work subcontracted. These limitations on the right to subcontract shall not limit or apply in any way to the purchase of power from other sources.

ARTICLE 4

GRIEVANCE PROCEDURE

Section 1. Definition and Procedure for Adjustment. A grievance within the meaning of the Agreement shall be a difference between the Utility and the Union or any employee of the Utility covered hereunder, as to the meaning or application of the provisions of this Agreement; provided, however, that a difference shall not be a grievance until it has first been discussed by the employee with his immediate supervisor without satisfactory adjustment. Such grievances shall be settled in the following manner:

STEP 1 — The aggrieved employee or employees shall present the grievance orally to the foreman or immediate supervisor of the employee and will then attempt to settle the grievance with the foreman or immediate supervisor of the employee as soon as possible. The immediate supervisor shall advise the employee or the Steward, as the case may be, by the end of the next working day after submission of the grievance, as to the Utility's answer to the grievance.

STEP 2 — If no satisfactory adjustment is agreed upon as provided in STEP 1, and the Union desires to pursue the matter, the grievance shall be presented in writing on a grievance form and provided to the employee's Department Head. The written grievance shall include a statement of the facts (i.e., the Company's alleged conduct, act, or omission which is being challenged, when it occurred, and the names of the foreman or supervisor and employees involved), and the remedy or correction requested, and each provision of the agreement violated. The grievance form shall be signed by the aggrieved employee or employees and a designated representative of the Union. The Department Head or some other official of the Utility with authority to act designated by the Utility shall review the alleged grievance and offer a decision within two (2) working days after the day the grievance is received.

STEP 3 — If no satisfactory adjustment is agreed upon as a result of the STEP 2 procedure and the Union desires to appeal the grievance to a higher authority, it shall be appealed to the Director of Human Resources or some other official of the Utility with authority to act designated by the Utility who shall review the alleged grievance and offer a decision within two (2) working days after the day the grievance is received.

STEP 4 — If no satisfactory settlement is agreed upon as provided in STEP 3, the matter shall be referred to the General Manager and/or to such other representative or representatives as the General Manager may designate, by the aggrieved employee or employees, the Steward, business manager and/or staff representative of the Union. The Utility representatives shall give an answer in writing within five (5) calendar days after the matter is submitted to the General Manager under this STEP 4. Following this STEP 4, the parties may, by mutual agreement, submit the grievance to mediation before a mutually agreeable mediator from the Federal Mediation and Conciliation Service.

STEP 5 — If no settlement of the grievance is reached in the foregoing STEPS, the matter shall be submitted to arbitration if either party shall so request in writing within thirty (30) days after the Utility's decision provided for in STEP 4. If the grievance is submitted to mediation and the mediation is not successful, the request for arbitration must be made within fifteen (15) calendar days of the date the mediation was attempted. The parties shall endeavor to agree upon an arbitrator, but if such agreement has not been reached within five (5) calendar days after the request for arbitration is delivered, then the matter shall be referred to the American Arbitration Association for the selection of an arbitrator pursuant to its Rules and Regulations. The decision of the arbitrator shall be final and binding on the parties.

Section 2. Time Limitations. Any grievance involving discharge not presented within seven (7) calendar days after the discharge and any other grievance not presented within twenty-one (21) calendar days of the occurrence of the event out of which the grievance arose shall not be entitled to consideration, and any grievance not appealed from one STEP of the grievance procedure to the next within fifteen (15) calendar days after the day upon which the answer is given shall be considered settled on the basis of the last answer, except for STEP 5 where fifteen (15) calendar days shall be allowed. Disciplinary write ups will not be used in progressive discipline after two (2) years have passed except those dealing with harassment prohibited by applicable civil rights laws and those dealing with violence or threats of violence.

Section 3. Arbitration Expense. The expense of arbitration, including the fee of the arbitrator, shall be borne equally by the Utility and the Union.

Section 4. Arbitrator Authority. The arbitrator may interpret the Agreement and apply it to the particular case presented to him, but he shall, however, have no authority to add to, subtract from, or in any way modify the terms of this Agreement or any agreements made supplementary hereto.

Section 5. Arbitrator Case Selection. No more than one unrelated case may be submitted to any arbitrator at one time except by mutual agreement of the parties.

Section 6. Union Stewards. The Utility agrees to recognize up to five (5) Stewards. Three of said Stewards may be designated Chief Stewards. A Steward or Chief Steward shall be permitted to leave his work station to investigate and adjust pending grievances referred to him by any employee in his department(s) after first securing the approval of the supervisor in charge, provided, however, that a Steward shall not spend more than four (4) hours per month away from his work for such purpose, and a Chief Steward shall not spend more than six (6) hours per month away from his work for such purpose. The supervisor shall have the right to determine whether or not the Steward can be spared from his work at a particular time.

Section 7. Representation Rights. An employee shall, upon request, have a right to have a Union Steward present at an investigatory interview which reasonably may be expected to lead to formal discipline.

Section 8. Personnel Record. Upon request an employee shall be allowed to inspect his personnel file in the presence of a Utility representative. Such employee will receive a copy of that file. Disciplinary write-ups will not be used in progressive discipline after two (2) years have passed except those dealing with harassment prohibited by applicable civil rights laws and those dealing with violence or threats of violence.

Section 9. Information Requests. The Utility and the Union recognize the right of either party to make reasonable and relevant information requests for purposes of collective bargaining. Although the parties agree that issues regarding information requests are not arbitral, each party shall nevertheless respond to such information requests, including any objections, within a reasonable period of time.

Section 10. Job Vacancy Grievances. Any grievance alleging a violation of Section 10.1, Job Vacancies, where the immediate foreman or supervisor of the aggrieved employee or group of employees has no jurisdiction in the selection process, shall be presented at Step 2 to the selection official and/or Department Head responsible for the position to be filled.

ARTICLE 5

PAY PERIOD

Wages shall be paid every two (2) weeks on Friday, except when Friday is a Recognized Holiday, and the payday shall be on Thursday. Not more than one (1) week's wages shall be withheld at any one time.

A note, signed by the employee, is required before a person, other than the employee himself, can obtain a check.

Advancements on wages will not be made under any condition.

Persons leaving the employment of the Utility for any reason will be required to wait until the regular payday to receive any wages due.

ARTICLE 6

VACATIONS

Section 1. Vacation Scheduling. The Utility agrees to give vacations with pay during each vacation year to employees who are eligible for vacation pursuant to this Article. The vacation year shall be the twelve (12) months period beginning January 1st and ending December 31st. Vacation schedules will be posted in each department during the month of January. So far as possible, vacations shall be granted during the week or weeks with employees having the longest term of Company service having preference as to dates selected prior to May 1, but the final right to allocate vacation time shall rest with the Utility in order to preserve the orderly operation of the Utility's business and meet the needs of the public. Should the employee's vacation not be scheduled by September 1, the employee and his Department Head shall meet to discuss available dates for the purpose of finalizing the schedule. In the absence of agreeing on dates, dates may be scheduled by the Department Head at his discretion. Vacation not taken during the vacation year is forfeited, except an employee who foregoes vacation at the Utility's request shall be paid for such vacation, provided, however, if the Company requires an employee to forgo a scheduled vacation and, as a result, has knowledge that the employee will lose and is unable after diligent efforts to recover a deposit on hotel and/or airfare, the Company will reimburse the employee for the unrecoverable portion of the deposit after presentation of documentation to establish the foregoing.

Section 2. Vacation Splitting. Employees, who are entitled to five (5) days or more vacation in a vacation year, may split into periods of not less than one (1) day with the approval of their Department Heads, which shall not be unreasonably withheld. Employees who are entitled to fifteen (15) days or more of vacation in a year, may be allowed to split into periods of not less than one (1) day at the sole discretion of their Department Heads. Employees who are entitled to twenty (20) days or more of vacation in a year, may be allowed to split into periods of not less than one (1) day at the sole discretion of their Department Heads. Employees who want to take a split day shall give at least 48 hours' notice of their desire to do so. All other vacations shall be scheduled in segments of five (5) days of vacation.

Section 3. Vacation Eligibility. Eligible employees who complete their initial six (6) months of employment after January 1st beginning a vacation year but before November 15 shall be entitled to five (5) days' vacation with pay in that vacation year after their six (6) months' anniversary date. Eligible employees who complete their initial six (6) months of employment after November 15 shall be entitled to five (5) days of vacation during the vacation year beginning the January 1 following. Eligible employees who have completed at least two (2) years seniority on or before January 1st beginning any vacation year shall receive ten (10) days' vacation with pay during the vacation year. Eligible employees who have completed at least seven (7) years seniority on or before January 1st beginning any vacation year shall receive fifteen (15) days' vacation with pay during the vacation year. Eligible employees who have completed at least fifteen (15) years seniority on or before January 1st beginning any vacation year shall receive twenty (20) days' vacation with pay during the vacation year. Eligible employees who have completed at least twenty-five (25) years seniority on or before January 1st beginning any vacation year shall receive twenty-five (25) days' vacation with pay during the vacation year. In order to be eligible for a vacation with pay during any vacation year, an employee must have worked at least one thousand two hundred fifty (1250) hours in the twelve (12) months preceding January 1st of that vacation year and be on the active payroll of the Utility as of that date. An employee who works less than one thousand two hundred fifty (1250) hours, but more than one thousand fifty (1050) hours in the twelve (12) months preceding January 1, shall receive five (5) days less than the vacation to which his seniority would otherwise entitle him. An employee with more than six (6) months' seniority as of January 1 who works less than one thousand fifty (1050) hours, but more than seven hundred seventy-five (775) hours in the twelve (12) months preceding January 1 shall receive five (5) days of vacation. An employee who works less than seven hundred seventy-five (775) hours in the twelve (12) months preceding January I shall receive no vacation, except an employee completing his initial six (6) months of employment prior to November 15 shall receive five (5) days of vacation if he worked more than seven hundred seventy-five (775) hours during his initial six (6) months of employment.

Eligible employees shall be entitled to a second, third, fourth and fifth week of vacation during the vacation year after their second, seventh, fifteenth and twenty-fifth anniversary dates respectively.

Section 4. Vacation Pay/Unused Vacation. One (1) week's vacation pay shall be an amount equal to the employee's regular straight time hourly rate in his own job multiplied by forty (40) hours. Employees whose employment is terminated shall be paid for vacation which they have not taken but to which they are entitled in that vacation year. If an employee dies before taking all of the vacation to which he is entitled, his estate shall be paid for the unused vacation. An employee who dies will be entitled to one-twelfth (1/12) of his vacation for each month actually worked in his last year of employment.

ARTICLE 7

HOLIDAYS

Section 1. Holidays Observed/Holiday Pay. Without working, any full-time permanent employee shall receive eight (8) hours' pay at his or her regular straight time hourly rate for each of the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, the day after Thanksgiving Day, Christmas Eve Day, Christmas Day, and effective January 1, 2020, four (4) personal days which may be taken in half shift segments and which must be scheduled by agreement with the employee's department head; provided, however:

(a) Any employee not normally required to work on any one of the above-enumerated holidays, who has been asked and agrees to work such holidays, and then does not work, will receive no pay for that day.

(b) Any employee who for any reason fails to work all of his scheduled workday immediately preceding one of such holidays and all of his scheduled workday immediately following such holiday will receive no holiday pay for such holiday unless the absence was excused by the employee's supervisor and the employee performed some work in the week in which the holiday falls; provided tardiness of less than fifteen (15) minutes will not disqualify an otherwise eligible employee from receiving holiday pay.

(c) Any employee who is normally required to work a holiday in accordance with his regular schedule, and who does not work, unless the absence was excused by the employee's supervisor, will not receive pay for that day.

For all hours worked by an employee during his regular scheduled working hours on any of the holidays listed above, the employee shall be paid at one and one-half (1½) times his regular straight time hourly rate. An employee who is not scheduled to work on a holiday but is called in to work on a holiday shall be paid at two (2) times the employee's regular straight time hourly rate for all hours worked on that holiday. For all hours worked outside his regular scheduled working hours by an employee on any of the above-listed holidays, the employee shall be paid at two and one-half (2½) times his regular straight time rate. In applying this section, for an employee called in (not scheduled) to work on a holiday, "regular scheduled working hours" shall be eight (8) consecutive hours beginning at the employee's regular starting time. For purposes of computing premium pay for holiday work, all hours worked by an employee shall be considered as having been worked on the day upon which the shift began. If a holiday is observed on a day other than the day on which it falls, the rates provided by this paragraph shall apply only to hours worked on the day on which the holiday is observed.

Section 2. Holidays Occurring During Vacation Period. If one or more of the days observed as a holiday falls during an employee's vacation period, the employee shall be entitled to extend his or her vacation period one (1) day for each observed holiday that falls during that vacation period.

ARTICLE 8

HOURS OF WORK

Section 1. Scheduled Hours/Shifts. The normal hours of work shall be eight (8) hours per day and forty (40) hours per week.

Employees shall be given seven (7) days' notice of permanent changes in regular work schedules, if possible. In the event such notice is not given when possible the employees whose schedules are changed shall be paid at one and one-half (1 ½) times their regular straight-time rate for the first two (2) shifts worked on the new schedule. Notice of change shall be sufficient if shown on the posted schedule or if the individuals affected are notified personally.

Section 2. Scheduled Work Week. All full-time bargaining unit employees who have completed their probationary periods and report for work as scheduled shall be assured of forty (40) hours of work per week, provided they were not laid off on or before their last scheduled workday of the preceding week. However, this assurance shall not require payment for time lost because of strike, work stoppage, fire, flood, or act of God, and the number of hours assured shall be reduced by the amount of time an employee loses by reason of vacation, holidays, sickness, injury, accident, leave of absence, voluntary layoff, disciplinary action, absence for personal reasons, funeral leave, jury duty, or similar reasons.

Section 3. Overtime. The workweek for the purpose of computing weekly overtime shall commence at 12:01 A.M. on Monday and shall consist of seven (7) consecutive days, The Utility shall have the right to change the workweek and normal hours of work provided written advance notice of such change is given to the Union and discussed with the Union upon request. All hours worked in excess of forty (40) hours in the workweek shall be paid for at the rate of one and one-half (1½) times the regular rate of pay. Employees will be paid one and one-half (1½) times their regular rates for hours worked in excess of eight (8) in a workday.

Section 4. Saturday and Sunday. Hours worked on Saturday by employees shall be paid at the rate of one and one-half (1½) times the employee's regular straight time rate of pay. Hours worked on Sundays by employees shall be paid at two (2) times the employee's regular straight time hourly rate of pay. Overtime and premium payments shall not be duplicated under any of the terms of this Agreement.

Section 5. Overtime List . Overtime work shall be awarded on a rotating basis (except when a crew has started a job and it continues into overtime hours or another day). An overtime list shall initially be posted by department and classification in order of unit seniority and overtime offered thereafter from the top of the current posted list. If insufficient employees accept the overtime, it shall be required in inverse order of classification seniority until the Company has determined it has sufficient manning. The list shall be changed every two weeks and posted on the bulletin board, with the top name rotating to the bottom of the list. New employees in the classification shall be placed at the bottom of the list. Employees shall not be required to take time off during their regularly scheduled working hours for overtime worked or to be worked. At least forty-eight (48) hours' advance notice for scheduled overtime will be given, unless it is impossible or impracticable to do so.

Section 6. Recall Minimum. If an employee has completed his regular scheduled workday, leaves the Company property, and is directed to report for work due to an emergency call in (which includes reconnects between the hours of 10 p.m. and 5 a.m.), the employee will be paid two (2) times the regular rate of pay so long as the employee has achieved at least a 50% response to emergency call ins. If the employee has less than a 50% response rate, the employee shall be paid time and one half. A minimum of two (2) hours at one and one-half (1½) times the employee's regular straight time hourly rate or the applicable hourly rate, whichever is higher, shall be paid to an employee who has left the Utility's premises and is called back to work. The foregoing shall also apply to employees serving as troublemen so long as enough journeymen linemen volunteer to participate in a minimum 6 week rotation. If insufficient employees volunteer, this provision shall not apply to employees serving as troublemen, who shall receive a minimum of one and one-half (1 ½) hours at one and one-half (1½) times the employee's regular straight time hourly rate or the applicable rate, whichever is higher, for each call out after they have left the Utility's premises. An employee who is called back to work under this section shall not be released when his assignment is completed if less than one hour remains before the start of his next regular scheduled workday.

Section 7. Rest Periods. Full-time employees shall be permitted two (2) rest periods each day, one (1) during the first half of the employee's shift and one (1) during the second half of the employee's shift. The time allowed for each such rest period shall be fifteen (15) minutes, and the rest period shall be taken at a time and place designated by the employee's supervisor. In extremely cold weather, trucks working off the Utility's grounds may take more than two (2) rest periods with prior management approval. The foreman in charge of each truck or job is responsible for the supervision of rest periods.

Section 8. Sixteen (16) Hours Premium. An employee who has worked sixteen hours consecutively shall be paid at two times the employee's regular hourly rate for all additional hours worked consecutively in excess of sixteen without being relieved of duty and permitted to clock out.

Section 10. Mutual Assistance.

(a) The purpose of this article is to establish a procedure for the assignment of personnel who are assigned to work on the property of another utility.

(b) The first mutual assistance opportunity after this Agreement becomes effective shall be offered by company seniority and further opportunities thereafter shall be offered on the basis of fewest cumulative credited mutual assistance hours. Mutual assistance hours accumulate from year to year. An employee who refuses a mutual assistance opportunity will be charged with the hours actually worked by the employee who performed the assignment. The company will post hours that have accumulated on a quarterly basis or as a result of a mutual assistance assignment. An employee who hires into or transfers into a classification shall be treated as if he/she had mutual assistance hours as an average between the then existing highest and lowest employees in the classification.

(c) Troublemen who volunteer for the list shall find their own replacement in order to accept an assignment if they are assigned to the trouble truck at the time of the initial assignment of mutual assistance.

ARTICLE 9

SENIORITY

Section 1. Layoff and Recall. Layoff and recall shall be by department, and it is recognized that the Utility's operation consists of the following departments:

Transmission and Distribution Department
Meter Department
Stores Department
Human Resources Department
General Office
Energy Services Department
Engineering Department
Operations Department
IS Department

The Utility shall have the right to change or eliminate departments during the term of this Agreement. Notice of such changes shall be given to the Union. In the event existing jobs are moved from one department to another, the Utility shall bargain with the Union about the seniority standing of the affected employees in the departments to which they are transferred.

Section 2. Layoff Procedure. When a reduction of force occurs in any department because of lack of work, the employee in the department with the least unit-wide seniority shall be laid off out of the department, provided the remaining employees in the department have the qualifications and present ability to do the remaining work. Such junior employee who is laid off out of a department shall have the right to displace any employee junior to him, provided he has the qualifications and present ability to perform the job, and the most junior employee in the department in which the employee is displaced shall leave the plant, provided the remaining employees have the qualifications and present ability to do the work. Whenever possible, the Utility shall attempt to give employees forty-eight (48) hours' notice of layoff for lack of work.

Section 3. Acquisition of Seniority. It is understood that unit-wide seniority shall be the length of the employee's continuous employment by the Utility since his last hiring date, regardless of whether or not such employment or parts of it has been worked in different job classifications in different departments. Any employee who is transferred to a position with the Utility outside the bargaining unit shall retain his unit-wide seniority and shall accrue additional seniority for a period of six (6) months while so working outside the bargaining unit. At the end of such six (6) month period, such employee's seniority shall terminate. Departmental seniority shall be the length of the employee's continuous employment in a particular department. An employee who transfers to another department shall retain his seniority in the old department until he successfully completes his tryout period in the new department, at which time his seniority in the old department shall terminate. An employee who transfers to another department shall retain his seniority in the old department if returned at the convenience of the Company within twelve (12) months

Section 4. Seniority List. A list giving the plant-wide and departmental seniority of each employee in the bargaining unit shall be prepared and posted by the Utility on the Bulletin Board within fifteen (15) days from the date of this Agreement. The seniority of any employee who does not within five (5) working days after the posting by the Utility of such list, file written exceptions with the Human Resources Department as to his seniority rating as shown by the said list, shall be considered correct as listed. However, if the parties mutually agree that an error has been made the error shall be corrected effective the date the error was reported in writing to the employee's supervisor. The Utility shall post a new and current seniority list each year on the contract anniversary date. A copy of the list shall be furnished to the Union.

Section 5. Probationary Employees. Probationary employees shall obtain seniority after six (6) months of employment, but probationary employees may be laid off, transferred or dismissed with or without cause during such six (6) month period. In case of layoffs, the Utility shall lay off such probationary employee before putting into effect the seniority policy, as stated above, provided employees with seniority have the ability to perform the work available. Probationary employees, after having fulfilled six (6) months' continuous service, shall date their seniority from the beginning of the six (6) month period.

Section 6. Acquisition of Seniority During Layoff. An employee on layoff shall be continued on the seniority list of the Utility for two years. An employee on leave of absence shall be continued on the seniority list of the Utility for a period of twelve (12) months.

Section 7. Loss of Seniority. The terms "continuous service" and "employed continuously" as used in this Article shall be so construed that absence from employment due to illness, accident, family deaths, or layoffs by the Utility shall not cause a break in the meaning of the word "continuous," for the purpose of computing seniority, vacation pay, and other provisions of this Agreement unless the employee's seniority is terminated. Seniority shall be terminated for any of the following reasons:

(a) If the employee quits;

(b) If the employee is discharged for just cause;

(c) If the employee is absent without leave for two (2) scheduled workdays without giving a valid reason to the Utility;

(d) If the employee fails to report for work or make satisfactory arrangements with the Utility within five (5) days after receiving notice to report by certified mail. Refusal of delivery by the employee or receipt by anyone at the employee's address shall be the same as receipt by the employee. Each employee shall, at all times, keep the Utility Office advised in writing of his current mailing address to entitle such employee to the benefits of this Article 9.

(e) If continuous layoff or absence because of sickness or injury extends beyond the limitations set forth in Section 6 of this Article.

(f) After six (6) months in a position outside the bargaining unit.

ARTICLE 10

JOB VACANCIES

Section 1. Filling Job Vacancies Within a Department. When a permanent vacancy occurs in a classification covered by this contract in any department, it shall be posted for three (3) working days in that department. Full-time bargaining unit employees in that department who have completed their probationary period may bid. Consideration shall be given to bidders on the basis of unit-wide seniority for non-progression jobs, provided the employees have the qualifications and present ability to do the job. Preference shall be given to bidders as follows:

(a) First, to employees in the classification next below the one in which the vacancy exists, and so on down, in accordance with existing lines of progression as set out on Exhibit A to this Agreement.

(b) Second, if the vacancy is not filled from employees in the line of progression or if there is no existing line of progression covering the classification, then such consideration shall be given to other employees in the department.

The Company may administer reasonable skills and/or job content tests to determine qualifications.

Section 2. Filling Job Vacancies in Line of Progression and Outside of Department.

A vacancy in a newly created bargaining unit job classification that is in a line of progression or a vacancy in an existing job classification which is not filled under Section 1 of this Article 10 or a vacancy in a newly created bargaining unit job classification that is not in a line of progression shall be posted for a period of not less than five (5) working days in all departments by the Director of Human Resources. (For purposes of this Section, newly created job classifications shall not include existing job classifications which are given new titles and/or revised duties and/or qualifications.) Full-time bargaining unit employees who have completed their probationary periods shall be eligible to bid. In selecting the successful bidder, the Company shall consider (a) qualifications and present ability to perform the work and (b) unit-wide seniority. When two (2) or more employees have qualifications and present ability to perform the work, the job shall be assigned to the employee with the most seniority. Preference shall be given to employees with seniority who have become physically unable to continue in their present jobs. The Company may administer reasonable skills and/or job content tests to determine qualifications.

Section 3. Trial Period. A bidder who is selected shall be given a trial period not to exceed three (3) months. Management may determine at any time that the employee has not demonstrated the necessary qualifications and present ability to do the job and terminate the trial period. If an employee is not able to perform the job satisfactorily, he shall be placed back on his or her former job. Unsuccessful more senior bidders shall be provided written reason(s) why they were not selected.

Section 4. Job Bidding Sanction. A successful bidder may not bid again for six (6) months except in recognized lines of progression as set out in Exhibit A. A successful bidder is an employee who bid on a posted job and was awarded that job. The six month bar to bidding shall begin at the time the employee accepts the award of the position. However, if the employee awarded the job is removed from the job during the trial period, the employee shall not be considered to be a successful bidder.

Section 5. Utility Assignment. If no one bids on a job, if no bidder has the qualifications and present ability to do the job, the Utility may fill any remaining vacancy or new job by either assignment of an employee of the same or lower-rated classification with the employee's approval, or by new hire, as the Utility sees fit.

Section 6. Temporary Assignments. While filling vacancies pursuant to this Article, the Utility may fill the job by temporary assignment.

Section 7. Apportion Period. If a successful bidder is not put on the job awarded within twenty-five (25) working days of the award and the delay is not attributable to the employee and the job has not been eliminated, the employee will be given the rate of the job awarded at the end of the twenty-five (25) working days or the employee's rate, whichever is higher. However, the employee's trial period under Section 3 will not begin until the employee is actually placed in the job.

Section 8. Job Postings/Job Descriptions. Copies of job postings shall be sent to the Union. If a job description for a bargaining unit position is revised during the term of this Agreement, the Utility shall send a copy of the new description to the Union. Upon request, an employee may inspect the job description for any bargaining unit position at a mutually agreed time.

Section 9. Lineman Progression. An employee who is hired or who bids or advances into the progression of Lineman at a level of 1st Year Lineman or above on or after October 1, 1992, may not bid out of that progression until completion of RPL's climbing assessment. If the employee fails the assessment, the employee will be returned to his/her prior job. Upon completion of the apprenticeship program, should the employee fail to qualify for advancement or decline to accept advancement to 2nd Year Lineman, 3rd Year Lineman, and 4th Year Lineman, the employee shall be subject to discharge. An employee in a classification above 1st Year Lineman who fails to qualify for or declines to accept advancement to the next higher position in the progression may, at the Utility's discretion, be required to bid on any open job in any department for which the employee would be an eligible bidder or, at the Utility's discretion, the employee shall be placed on layoff, subject to the limitation of Article 9, Section 6, until he or she is able to successfully bid on an open job. An employee may be required to repeat a section of training more than once at the Utility's discretion. After two failures to successfully complete training of a section, the employee will be subject to discharge. This Section 10 of Article 10 shall not apply to employees who are in the Transmission and Distribution Department on October 1, 1992.

Section 10. Truck Driver/Ground Person - Equipment Operator Wage Protection. The rate of an employee who is at the maximum rate for Truck Driver/Ground Person or the maximum rate for Equipment Operator shall not be reduced if the employee bids into an Apprentice Lineman position. He shall continue at the Truck Driver/Ground Person or Equipment Operator rate until the employee's rate in the Lineman progression exceeds the employee's rate for Truck Driver/Ground Person or Equipment Operator, as the case may be. During this time, the employee's Truck Driver/Ground Person or Equipment Operator rate shall receive annual contract increases. The rate of an employee who is at the maximum rate for Truck Driver/Chipper Operator shall not be reduced if the employee bids into the Apprentice Tree Trimmer position. He shall continue at the Truck Driver/Chipper Operator rate until the employee's rate in the Tree Trimmer line of progression exceeds the employee's rate for the Truck Driver/Chipper Operator. During this time, the employee's Truck Driver/Chipper Operator rate shall receive annual contract increases.

ARTICLE 11

TEMPORARY TRANSFERS

Section 1. Temporary Transfer Pay Differential. Whenever an employee is temporarily required by the Utility to perform work which is in a classification at a lower rate of pay, the employee shall be paid the rate of pay for his regular work. Whenever an employee is transferred other than temporarily to work which is in a classification at a lower rate of pay, said employee shall be paid the rate of pay applicable to the work to which he is transferred. Any employee temporarily assigned to work in a higher paying classification for more than two (2) hours will receive not less than the base rate of the higher-rated classification for all hours worked in such higher-rated classification. An employee who works four hours or more on a holiday in a classification at a higher rate of pay shall be paid holiday pay at the higher rate if the employee is eligible for holiday pay.

Section 2. Forty-Five (45) Day Temporary Transfers. Temporary transfers which are reasonably expected to exceed forty-five (45) days shall be offered to lower-rated employees known to have the qualifications and present ability to perform the work needed in order of seniority beginning with employees in the department where the work is to be done. If no such employee accepts the offered temporary transfer, the Utility may require the most junior employee with the qualifications and present ability to accept the transfer.

Section 3. Six (6) Month Time Limitation. Temporary transfers under this Article shall not exceed six months except for employees temporarily assigned as a result of an employee taking union leave under Article 14, Section 3, or when a longer period is mutually agreed in a particular case.

Section 4. In-Grade Pay Adjustment During Temporary Transfer Period. For each 110 days that an employee has actually worked in the same classification on temporary transfer, the employee's rate for hours worked in that classification shall be advanced to the next six months level until the maximum rate for that classification is reached. Each day during which the employee is temporarily transferred to a classification for more than two hours shall count as a day worked for purposes of this paragraph.

ARTICLE 12

SAFETY AND HEALTH

Section 1. Company Obligation. The Utility shall continue to make reasonable provisions for the safety and health of its employees during hours of employment. To the extent protective devices on equipment are now being provided or are necessary to properly protect employees from injury, such devices shall be provided by the Utility during the life of this Agreement.

Section 2. Employee's Obligation. Employees shall use and make every effort to preserve the equipment provided for their safety and shall observe and abide by OSHA regulations, the Safety Rules and established Company safety policies. Supervisors shall not request an employee to disregard any mandatory Safety Rule.

Section 3. Working Outdoors. No employee shall work alone outdoors on or dangerously near energized conductors or parts of more than 600 volts between conductors. This shall not preclude a qualified employee, working alone, from cutting trouble in the clear, switching, replacing fuses, or similar work if such work can be performed safely.

ARTICLE 13

EQUIPMENT AND CLOTHING

Section 1. Company Option. At the option of the Utility, employees may be issued keys, badges, uniforms and accessories for use in connection with their work as specified by the Company.

The Utility will furnish tools and protective equipment it considers applicable to the job, such as rubber gloves, rubber boots, goggles, and hot line tools for work on energized lines, etc. The Utility will furnish a lineman an initial lineman belt, safety and climbers.

The Utility will furnish rain and mud gear for all employees whose jobs require outside work under these conditions.

Section 2. Employee Reimbursement. In the event any or all of the Utility-owned equipment issued to an employee is lost, destroyed, or misused through his fault or neglect, or in the event the employee leaves the service of the Utility without returning such items to the Utility, he shall pay the Utility for the same. Employees shall authorize the deduction from their pay of any amounts owed under this Section.

Section 3. Replacement of Personal Tools. Hand tools owned and used by an employee in his work will, at the expense of the Utility, be repaired or replaced with those of like quality if worn out or broken in the course of his employment with the Utility to the extent that it determines that such tools are necessary for his work. Any broken or worn out tools must be turned in and shall become the property of the Utility upon replacement.

Section 4. Eyeglasses And Dentures. An eyeglass lens and frames broken or damaged beyond continued use while being worn and used by an employee in his performance of assigned work duties in a manner consistent with safety regulations and instructions, will be replaced or repaired at Utility expense. Broken lenses will be replaced with like lenses. Dentures broken or damaged while being worn by an employee in his performance of assigned work duties in a manner consistent with safety regulations and instructions will be repaired at Utility expense, provided the employee reports the breakage immediately and furnishes a receipt for repair cost.

Section 5. Work Gloves. Employees welding and performing line work, and others whose regular assignments of work, in the judgment of the Utility, include the handling of materials or equipment as may reasonably require the wearing of gloves, will be furnished work gloves and such gloves will be replaced when the employee turns in worn out gloves.

Section 6. Shoes. The utility will pay a maximum of $100 per calendar year for shoes upon approval of appropriate footwear by safety committee (such payment to be retroactive for those who have purchased appropriate footwear on or before November 19, 2012 if approved by the safety committee). The annual payment carries over to the following year if not used, subject to a $300 maximum accumulation.

ARTICLE 14

LEAVES OF ABSENCE

Section 1. General. The Utility may grant leave of absence at its discretion upon written application for a period not to exceed ninety (90) days. Such leave of absence may be extended to six (6) months with the written approval of the Utility. All leaves of absence shall be in writing, and no employee who is on leave of absence shall accept employment with another employer, unless his written leave of absence so provides. Failure to comply with these provisions shall result in the termination of employment of the employee involved.

Section 2. Disability. An employee on disability leave, including disability resulting from maternity, must furnish upon request written statements from a physician that he or she is or is not able to work.

Section 3. Union Office. A bargaining unit employee who is elected or appointed to a Union office shall upon request be granted a leave of absence of up to three years without pay. No more than one employee shall be granted such leave at any one time. The Utility will consider a request to renew a leave under this Section for a period beyond three years, but the grant of such renewals shall be discretionary.

Section 4. Union Conferences/Meetings. Leave of absence without pay to attend Union conventions, conferences, or committee meetings shall be granted upon thirty (30) days' notice by the employee and at the written request of the Union provided that (1) the leave does not interfere with the orderly operation of the Utility's business, (2) no more than two (2) employees shall be allowed such leaves at the same time, (3) the number of workdays missed during a year by all employees on such leaves may not total more than ten (10), and (4) no single leave under this section shall exceed five (5) workdays.

Section 5. Family And Medical Leave. Leaves covered by the Family and Medical Leave Act (FMLA) shall be administered in accordance with the FMLA. The provisions of Section 1 of this Article relating to employment by another employer while on leave shall apply to FMLA leaves also. If an FMLA leave is because of the serious health condition of the employee, an employee must use at the beginning of the leave any sick days which the employee has accrued and sick days so used shall be part of the FMLA leave. An employee may use vacation for part or all of an FMLA leave, but for absences for which the employee receives daily worker's compensation benefit, vacation time may only be used to make up the difference between the compensation received and the employee's normal daily earnings. FMLA leave time will be administered by using a rolling twelve (12) months backward from the date an employee uses FMLA leave as the twelve (12) month period in which an eligible employee may take up to twelve (12) weeks of FMLA leave.

ARTICLE 15

SICK LEAVE

Section 1. Sick Leave Crediting and Accumulation. On January 1st each year, each full-time permanent employee on the active payroll shall be credited with fifteen (15) days sick leave except employees hired during the preceding twelve (12) months, who shall be credited with 1.25 days of sick leave for each full month worked from their date of hire through December 31. Employees may accumulate unused days of sick leave up to a maximum of one hundred five (105) days. Any unused days in excess of one hundred five (105), shall be forfeited at the end of each year. Effective January 1, 1994, an employee who has accumulated 105 days of sick leave and thereafter does not use any sick leave for a full calendar year shall be entitled to a bonus day during the year following that calendar year that may be split into two half days.

Section 2. Sick Pay Computation. A day's sick pay shall be eight (8) hours' pay at the employee's regular straight time hourly rate, except in cases where the absent employee is receiving daily workmen's compensation payment. In such cases the employee shall receive the difference between the workmen's compensation payment and eight (8) hours at the employee's regular straight time hourly rate, and each day so paid shall be counted as one-third (⅓) day's sick pay.

Section 3. Sick Pay During Hospitalization. An employee shall be entitled to sick pay immediately upon admission to a hospital, provided the employee furnishes a certificate of proof from the hospital, or beginning the day that the employee undergoes a recognized surgical procedure by a physician as an out-patient, provided the employee furnishes verification from the attending physician. In all other cases, an employee shall not be entitled to sick pay until a one (1) shift waiting period requirement has been satisfied.

An employee who has once satisfied the waiting period requirement shall not be required to satisfy it again for the same illness if the illness recurs within two (2) weeks of his return to work.

The one-shift waiting period will not be enforced unless the following circumstances have occurred: If more than forty (40) sick occurrences happen in a six (6) month period ending March 31, 2011 or any successive six (6) month period, the Company will review such circumstance to determine if any abuse has occurred. The Company will meet with the Union to discuss such circumstances. If abuse is observed, the one-shift waiting period will be reinstituted not less than fourteen (14) days after the meeting with the Union.

Section 4. Sick Pay During Illness/Holidays/Disability. An employee may receive sick pay only for his regular scheduled workdays missed because of illness and for holidays for which he does not receive holiday pay. Employees on leave of absence or layoff shall not be entitled to sick pay, but an employee may use any days paid sick leave to which the employee is entitled prior to commencement of a leave of absence because of sickness or illness, including disability resulting from pregnancy.

Section 5. Sick Leave Procedure. To be entitled to sick leave an employee must:

(a) Report the cause of his absence before the starting time of the first scheduled workday of absence unless the giving of such notice is impossible.

(b) Submit upon request verification of the illness and its duration from a doctor of medicine, dentist, or other practitioner of medicine who is licensed to prescribe prescription medications.

(c) Upon request of the Human Resources Department, present at reasonable intervals a certification from the attending practitioner as defined in (b) of this Section 5 that the employee is disabled.

(d) Promptly adopt such remedial measures as may be commensurate with his or her disability.

Section 6. Sick Leave Prohibition. No employee will be entitled to sick pay allowances hereunder:

(a) For disabilities resulting from the employee's commission of any crime or caused by the use of unlawful drugs or intoxication (provided, however, an employee may use sick days for attendance at a bona fide drug or alcohol rehabilitation program which the employee must complete);

(b) For disabilities occurring while in the hire of an employer other than the Utility or for remuneration through self-employment;

(c) For any period during which he or she is performing any work for remuneration or profit.

ARTICLE 16

FUNERALS

Section 1. Funeral Leave Duration(s). Full-time permanent employees shall be entitled to funeral leave in the following amounts as indicated:

(a) At time of death of employee's wife, or husband, or child--a maximum of five (5) scheduled workdays. "Child" shall include stepchildren who live in the employee's home.

(b) At the time of death of an employee's mother, father, brother or sister, stepchild who has not lived in the employee's home, stepparent or any person in the relationships named in (c) of this Section if living in the employee's household — a maximum of three (3) scheduled workdays.

(c) At the time of death of an employee's mother-in-law, father-in-law, brother-in-law, sister-in-law, son-in-law, daughter-in-law, grandchild or grandparent or spouse's grandparents — a maximum of two (2) scheduled workdays.

Section 2. Funeral Leave Procedure. Funeral leave days must be taken between date of death and the day following the funeral except the days of leave under (a) above must be taken consecutively and must include the day of the funeral. Days of funeral leave shall be paid at the rate of eight (8) hours per day at the employee's regular straight time rate of pay. The days paid as funeral leave under this Article shall be only regular scheduled workdays.

Section 3. Funeral Leave Abuse. In cases of suspected abuse the Utility may require an employee to submit to the Human Resources Department, upon his return, proof of relationship and verification of the death of such relative. If the employee does not attend the funeral, he will not be entitled to any payment.

Section 4. Pay Practice as Pall Bearer. The Utility shall pay an employee up to four (4) hours at his regular straight time rate for hours actually spent serving as a pall bearer for an employee, a member of an employee's immediate family, or a retired Utility employee, provided proper advance notice is given to the Utility. The immediate family for purposes of this Section shall include the grandfather, grandmother, granddaughter, grandson, father, mother, mother-in-law, father-in-law, brother, sister, wife, son, daughter, son-in-law and daughter-in-law of the employee.

Section 5. Attendance at Funeral of Co-Worker. In the case of an employee's death, the Utility may in its discretion, grant a limited number of employees time off without loss of pay to attend the funeral.

ARTICLE 17

MILITARY LEAVE

Section 1. Military Service. Regular employees who leave the service of the Utility to enter that of the United States Armed Forces or are drafted in the service of the U.S. Maritime Commission or who are drafted by the United States Government for civilian service will, upon their return within ninety (90) days from release from such service, be granted such reinstatement and seniority rights as such employee is entitled to under the applicable provisions of law.

Section 2. Indiana National Guard/Armed Forces Reserves. The Utility shall comply with applicable provisions of I.C. § 10-2-4-3 for employees who are members of the Indiana National Guard or reserve components of the United States armed forces. To be entitled to such coverage the employee must present to the Utility military orders showing the amount of time to be spent on active duty.

Section 3. Active Duty Training. The employee shall consult the Utility if he has a choice of training periods so that time off can be arranged during a slack season. If the employee must report for active duty at a specified time not of his own choosing, he must notify the Utility as soon as possible as to the time of his departure and the duration of his duty.

ARTICLE 18

JURY DUTY

An employee who is called for jury service shall, for time lost from his regular shift because of such service, be paid the difference between his per diem pay for jury service and his wages (limited to eight (8) hours per day and forty (40) hours per week at the employee's regular straight time hourly rate. An employee shall not be scheduled to work on a day on which he has served or is scheduled to serve a full day as a juror, provided an employee who is released from jury duty prior to the end of his regular shift shall notify the Utility and report as requested.

ARTICLE 19

RETIREMENT AND RETIREMENT FUND

Section 1. Company/Employee Contribution. During the term of this Agreement, the Utility shall maintain its defined benefit plan for employees on the payroll on or prior to September 30, 2013. For such employees, the company shall continue to contribute to the Retirement Plan 11% of the total pay of a participating employee. Each participating employee shall contribute 4% of his total pay to the Retirement Fund. Any increases in required contributions shall be shared by the Utility and the employee in proportion to their respective contributions. Only employees on the payroll on or prior to September 30, 2013 are eligible to participate according to the terms of the plan document, which is incorporated herein except as it conflicts with this document.

Section 2. Defined Contribution Plan. Only employees hired after September 30, 2013 shall be eligible to participate in the defined contribution plan. The company shall contribute 8% of a participating employee's total pay. Each participating employee shall contribute 3% of total pay to the defined contribution plan. In addition, the company shall match 100% of the employee's voluntary contributions to the defined contribution plan up to a maximum of 3% of the employee's total pay.

Section 3. Company Discretion. The Utility shall have the right to change insurance carriers provided there is no reduction in benefits because of such change. The Utility shall have the right during the term of this Agreement to amend the Retirement Plan at its discretion to comply with applicable laws.

Section 4. Vacation at Retirement. A retiree will be entitled to one-twelfth (1/12) of his vacation for each month actually worked in his last year of employment.

Section 5. Pension Information. The Company shall provide the Union with the annual actuarial evaluation report of the defined benefit plan.

ARTICLE 20

INSURANCE

Section 1. Group Insurance. During the term of this Agreement, the Utility will pay 93% of the premium for coverage of eligible full-time employees and 70% of the premium for coverage of dependents of eligible full-time employees electing such coverage pursuant to the NECA/IBEW Family Medical Care Plan 16 effective January 1, 2014 (employees remain in the current insurance plan until December 31, 2013). The plan may be changed by the carrier or administrator. If more than one network PPO plan is offered by the carrier or administrator, the Utility may select which plan or plans to offer. Full-time employees and their dependents shall become eligible for coverage according to the terms of the plans. The Utility shall pay 90% of the premium cost for a participating employee for coverage under the Utility's Group Life Insurance (in addition to life insurance provided by the NECA/IBEW plan). Union to designate a representative to regularly meet with Utility's HR Department representative to review group life insurance rates and health care utilization.

Section 2. Company Obligation. The obligation of the Utility for the payment of its share of such insurance cost shall cease immediately in case the employee quits, is discharged, or participates in a strike or a work stoppage. In the case of layoff of the employee by the Utility or leave of absence for reason other than sickness or injury, such obligation shall terminate at the end of the month in which the layoff occurs or the absence begins. In the case of absence because of sickness or injury such obligation shall terminate six (6) months from the commencement of such absence. The Utility shall have the right to change insurance carriers at its discretion, provided there is no reduction in benefits.

Section 3. Healthcare Law Changes. If a national, state, or local healthcare statute, ordinance, or plan is adopted, amended or modified and/or becomes effective or applicable to the parties during the term of this Agreement, and if it requires the Company to incur healthcare costs greater than or beyond those already provided in this Article, the parties agree to bargain over this Article 20. This section shall not be applicable unless the change in law referenced herein results in a healthcare cost increase to the Company greater than 10% annually. Such negotiations shall be scheduled at a reasonable time, date and place following written notice to the Union. If the parties fail to reach agreement, the no-strike/no-lockout provisions of this Agreement shall not apply and either party may take action it deems appropriate.

ARTICLE 21

WEATHER

Section 1. No Lay Off Due To Inclement Weather. Employees reporting at their regularly designated time and place to perform their work will not be laid off by the Utility due to inclement weather.

Section 2. Lines Department. The Utility will not require Line or Engineering Department employees to work on the electric lines or outdoor substations (other than operating functions) in inclement weather, except in the case of emergencies. Emergencies shall include situations requiring work to prevent risk to life or property or to maintain or restore continuity of service to the public. When not required to work outside, Line or Engineering Department employees may be required to perform any work which they are able to perform under protection from the weather. Inclement weather shall for purposes of this Section include severe cold weather, which shall be considered any degree of temperature 10 degrees above zero or less. Temperature readings shall be accepted as given by the local weather observation station.

Section 3. Meter Readers/Meter Department. Meter Readers and Meter Department employees will not be required to work outside when the temperature is below 10 degrees except in emergencies and as necessary to read the meters, of industrial customers and large power users. When not required to work outside they may be required to perform any work which they are able to perform under protection from the weather.

ARTICLE 22

NO INTERRUPTIONS IN WORK

The Union and its members, individually and collectively, will not, during the life of this Agreement, encourage, cause, permit, or take part in any strike, picketing, sit-down, stay-in, slow-down, sympathy strike, or other curtailment of work or interference with production in or about the Utility's plant or premises.

Correlative with this provision, the Utility will not engage in a lock-out during the term of this Agreement.

However, an employee shall not be required to cross a lawful picket line at another employer's place of business except in emergencies.

ARTICLE 23

MISCELLANEOUS

Section 1. Educational Assistance. The Utility shall pay all of the tuition charge and cost of required textbooks for courses which it feels will make the employee a more valuable asset. To receive payment for the course, the employee must complete the course and receive at least a C grade and the course must be approved in advance by the Utility.

The Utility also will pay all of the tuition charge and cost of required textbooks for courses which it has requested the employee to take. Such requests must be in writing, signed by the Director of Human Resources. The Utility may stop the employee's course if it feels that the employee is not making a passing grade.

Section 2. Bulletin Boards. The Utility will provide a space on the Bulletin Board on which Union notices may be posted after the notices have been submitted to the Director of Human Resources and approved in advance of posting.

Section 3. Telephones. Employees may make personal phone calls on Utility phones only with permission of their department head. No calls shall be permitted between 7:00 and 8:00 A.M. The Utility, at its option, may install pay telephones for employees and require that all personal calls be made on the pay telephones.

Section 4. Meal Allowance. An employee shall be entitled to a meal if the employee is required to work more than ten continuous hours including hours on the employee's regular shift and shall be entitled to an additional meal for every six (6) hours of continuous work after the first entitlement. An employee who is called in to work for more than two hours on a scheduled day off or holiday or outside his or her regular shift shall be entitled to a meal as nearly as practicable at 6:00 p.m., 12:00 midnight, and 6:00 a.m. An employee entitled to a meal shall be provided a meal by the Utility or shall receive a meal allowance of $8.50, which amount shall be increased to $10.00 effective January 1, 2020.

Section 5. Supervisors Working. Supervisory personnel shall not perform work normally performed by members of the bargaining unit except (1) for the purpose of instruction or training, (2) when starting and testing new equipment, methods or processes and performing experimental work, (3) in emergencies, and (4) when work is impeded because one or more qualified unit employees are unavailable or absent for reasons other than layoff. Working foremen in addition may continue to perform work as they have in the past.

Section 6. Lineman/Lineman Apprentice Ratio. The ratio of Apprentice Linemen to Journeymen Linemen shall not exceed two (2) apprentices to each four (4) Journeymen Linemen.

Section 7. Digging Pole and Anchor Holes. Journeymen Linemen will not be required to dig pole and anchor holes by hand.

Section 8. Drug and/or Alcohol Testing. The Utility shall have the right to establish a reasonable mandatory drug and/or alcohol testing program that does not reduce the rights that employees have under law. Any such testing programs shall not include random testing except to monitor an employee who has returned to work after completing a rehabilitation program. Testing after an accident involving personal injury requiring medical attention beyond first aid or damage to property exceeding $500.00 shall not be considered random; provided no employee shall be subject to testing when the triggering incident clearly involved an act of God, or where it is clear that the employee was not at fault. The Union and the Utility agree that the Union and/or an employee, or group of employees, have the right to challenge the reasonableness and/or application or interpretation of any such testing program on a case-by-case basis in the grievance procedure.

Section 9. Commercial Driver's License (CDL). For an employee required to have a Commercial Driver's License (CDL), the Utility will pay the cost of the physical examination required for obtaining or renewing a CDL if the employee obtains the physical examination from a clinic or physician designated by the Utility. In addition, for an employee required to have a

CDL the Utility will pay the charge for the written CDL examination. The Utility will pay the charge for a driving skills test for an employee who does not have a chauffeur's license and is obtaining a CDL for the first time.

Section 10. Residency Requirement. Employees hired into or transferring into classifications in the Lineman, Tree Trimmer and Truck Driver Ground Person progressions on or after October 1, 1994, must live within a twenty (20) mile radius of 8th and East Main to remain in those classifications.

An employee who is hired or transfers into one of those classifications after October 1, 1994, and moves his or her residence outside that limit shall be subject to termination.

This section shall not apply to employees who are on the Utility's payroll of September 30, 1994.

Section 11. Job Classification Changes. The Company will give written notice to the Union of any new classification, changes, or elimination of existing classifications including a job description and the salary grade at least 14 calendar days prior to the effective date of the change and shall, upon request, discuss with the Union the changes and/or salary grade. The Company's right to establish new job classifications or modify existing classifications shall not be exercised for the sole purpose of reducing a specific employee's wage rate. Neither shall the Company change a job description for the sole purpose of excluding a specific employee from eligibility to bid on any impending vacancy.

ARTICLE 24

WAGES

Section 1. Rates of Pay. During the term of this Agreement, the hourly rates of each employee in the bargaining unit shall be as set forth in the Appendix.

Section 2. Crew Leader Premium. An employee who, at the request of his supervisor, leads the work of two or more other employees in field work where direct supervision is not readily available, shall be paid a premium of $1.00 per hour for all hours worked in that capacity, which shall be increased to $1.25 for all hours worked in that capacity effective January 1, 2020, and $1.50 per hour for all hours worked in that capacity effective January 1, 2021.

Section 3. Troubleman Watch Premium. Effective during this Agreement, an employee shall be paid $185.00 for each full week in which he serves as Troubleman; effective January 1, 2020, $196.00; effective January 1, 2021, $203; effective January 1, 2022, $210. This payment shall be in addition to pay for all hours worked at the applicable rate.

Section 4. Use of Personal Vehicle. When an employee is requested to use his personal automobile in Utility service and does so, it shall be under the established rules of the Utility and for such use the Utility shall pay the mileage allowance recognized by the IRS.

Section 5. Air Hammer Premium. An employee shall be paid a premium of 50¢ per hour for time actually spent operating an air hammer.

Section 6. Mutual Assistance Premium. Subject to Article 8, Section 10, an employee assigned to perform emergency work on the property of another utility shall be paid at two times his or her regular straight time hourly rate. This section shall not apply to the Utility's interconnections with other utilities or to any IMPA property.

ARTICLE 25

REASONABLE ACCOMMODATION

The Union and the Utility recognize the legal obligation of the Utility to make reasonable accommodation for certain employees or applicants for employment with disabilities. The Utility reserves the right to make such accommodations as may be required, and the Union agrees to cooperate with the Utility in meeting its legal obligation. Making reasonable accommodation, as required by law or applicable regulation, for a qualified employee or applicant with a disability will not be considered to violate or add to the rights of any other employee under this Agreement. Specifically, and without limiting the generality of the foregoing, the Utility's reallocation or redistribution of non-essential job functions to other employees, if reasonable and necessary to accommodate a qualified employee or applicant with a disability, will not be considered a violation of the rights of the other employees under this Agreement and shall not entitle them to additional compensation. If accommodation within the current classification of an employee with a disability is not possible or would pose an undue hardship, the employee will be considered automatically as an applicant for all posted job vacancies and may be selected in accordance with the provisions of Article 10 of this Agreement. The Utility and an employee with a disability may agree upon a part-time or modified work schedule without violating this Agreement. If the Utility's action in making reasonable accommodation is challenged through the grievance procedure, no violation of this Agreement may be found if the Utility's action was required by law or applicable regulation.

ARTICLE 26

EMERGENCY CALL-INS

Section 1. Lines Department. For purposes of emergency call-ins in the Line Department, the Utility shall maintain for each classification in that department a call-in list. Hours worked by employees, including Troublemen, on emergency call-ins shall not be charged against them for purposes of overtime equalization. However, the Utility shall not be required to assign scheduled overtime to a Troubleman during a week in which he or she serves as Troubleman.

Section 2. Call-In Procedure. When emergency call-in work is necessary, the Utility shall first call employees by classification in rotation and the rotation shall advance every pay period. That is, at the end of a pay period, the top name on the list during that pay period shall go to the bottom of the list. This Article shall not in any way relieve any Line Department employee of the duty to work overtime as required.

ARTICLE 27

AFTER HOURS SERVICE WATCH

All Journeyman Linemen and 4th year Linemen having completed at least 7,000 hours of training living within a 20 mile radius of 8th and East Main and having a telephone will be eligible to serve as an after regular working hours troubleman. The service watch will be on a six week rotating basis. RPL shall post a list each October 1st for two weeks. Sufficient employees must sign up to ensure a 6 week rotation and shall choose slots by classification seniority. If insufficient employees volunteer, RPL shall apply the after hour service watch policy which was in effect during the contract beginning November 28, 2012.

Each troubleman on the rotating list will work trouble for one week, beginning at the end of his regular shift on Monday till the end of his regular shift the following Monday.

When a temporary vacancy occurs and no eligible lineman agrees to cover the absence, then the employees with the least classification seniority in the eligible classification who is not on the after hours service watch list will be required to take the troubleman assignment. If everyone has signed up for the after hours service watch list, then the employee with the least classification seniority shall work the vacant troubleman assignment unless such employee just completed a week-long assignment during the previous week.

An employee on the list can trade his day or week to work trouble with another troubleman or another eligible, qualified employee who wants to work trouble for him, as long as arrangements are made in advance and approved by the Transmission and Distribution Department Superintendent and so long as the trade does not result in additional cost to the Company. The employee that works the troubleman schedule will receive the pay for work performed.

As in the past the troubleman shall be permitted to call in help when he or the Transmission and Distribution Department Supervisors feel help is needed. Help called for shall depend upon the nature of the trouble.

ARTICLE 28

TERMINATION OF AGREEMENT

This Agreement shall become effective as of the 1st day of October 2019, and shall remain in full force and effect until the 30th day of September 2022, and shall renew itself from year to year thereafter, unless written notice of termination or desired modification is given at least sixty (60) days prior to the expiration date by either of the parties hereto.

The post office address of the Utility is Box 908, Richmond, Indiana 47375.

The post office address of the Union is 5140 Madison Avenue, Indianapolis, Indiana 46277.

COMMON COUNCIL OF THE CITY OF RICHMOND

Randall Baker

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395

Mark McFarland

Richard B. Napier

Derek Jordan

David Drudy

Michael Baker

Mark Sharits

Mike Drook

Dave Samuels

Mike Berger

EXHIBIT A

LINES OF PROGRESSION

Only those positions connected to each other with lines are promotional progressions. Positions not so connected are shown merely to indicate their departmental location.

Laborer under Equipment Operator

Electrician Repair under Electrician C

Truck Driver under 1st Year Lineman

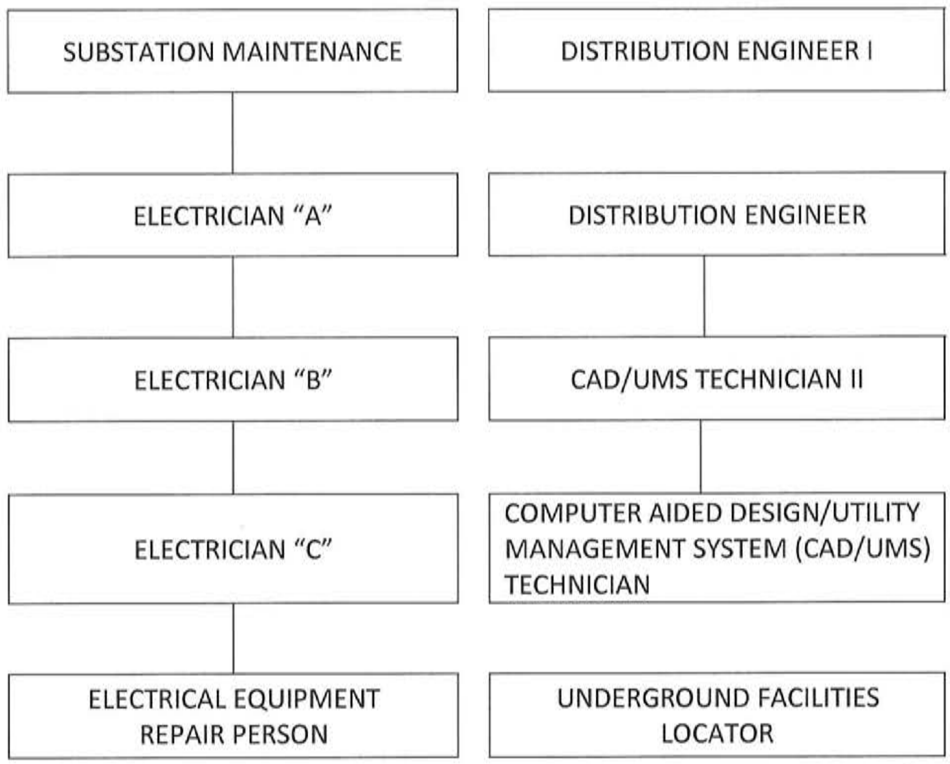
PROMOTIONAL CHART
RICHMOND POWER & LIGHT
ENERGY SERVICES DEPARTMENT

CUSTOMER SERVICE CLERK

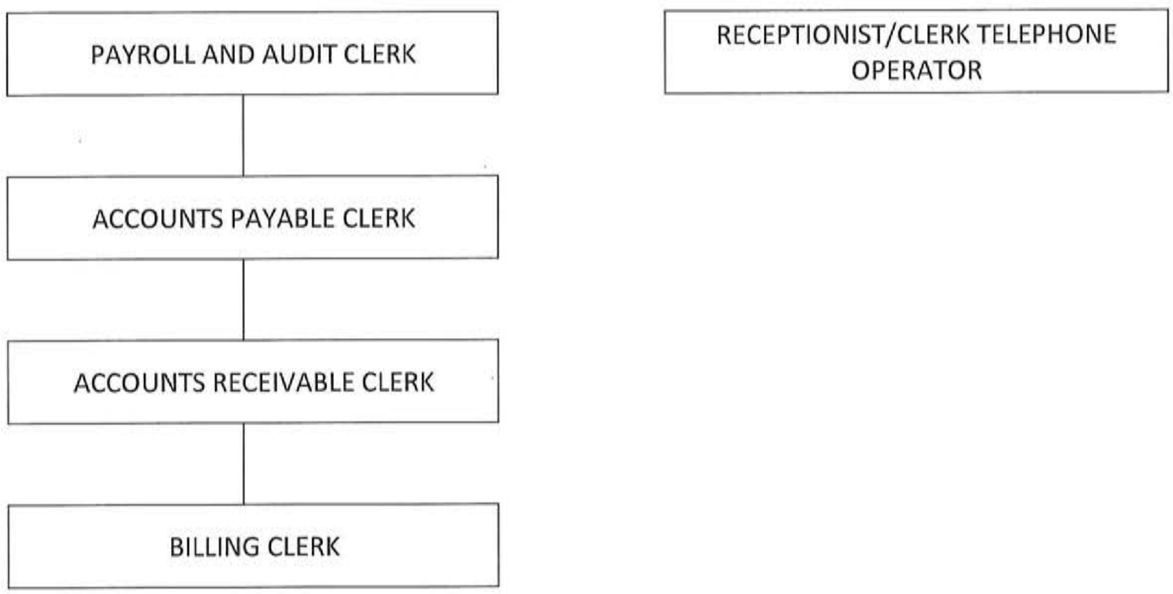
SERVICE PERSON

ENERGY SERVICES UTILITY PERSON

PROMOTIONAL CHART
RICHMOND POWER & LIGHT
ENGINEERING DEPARTMENT



PROMOTIONAL CHART
RICHMOND POWER & LIGHT
GENERAL OFFICE DEPARTMENT



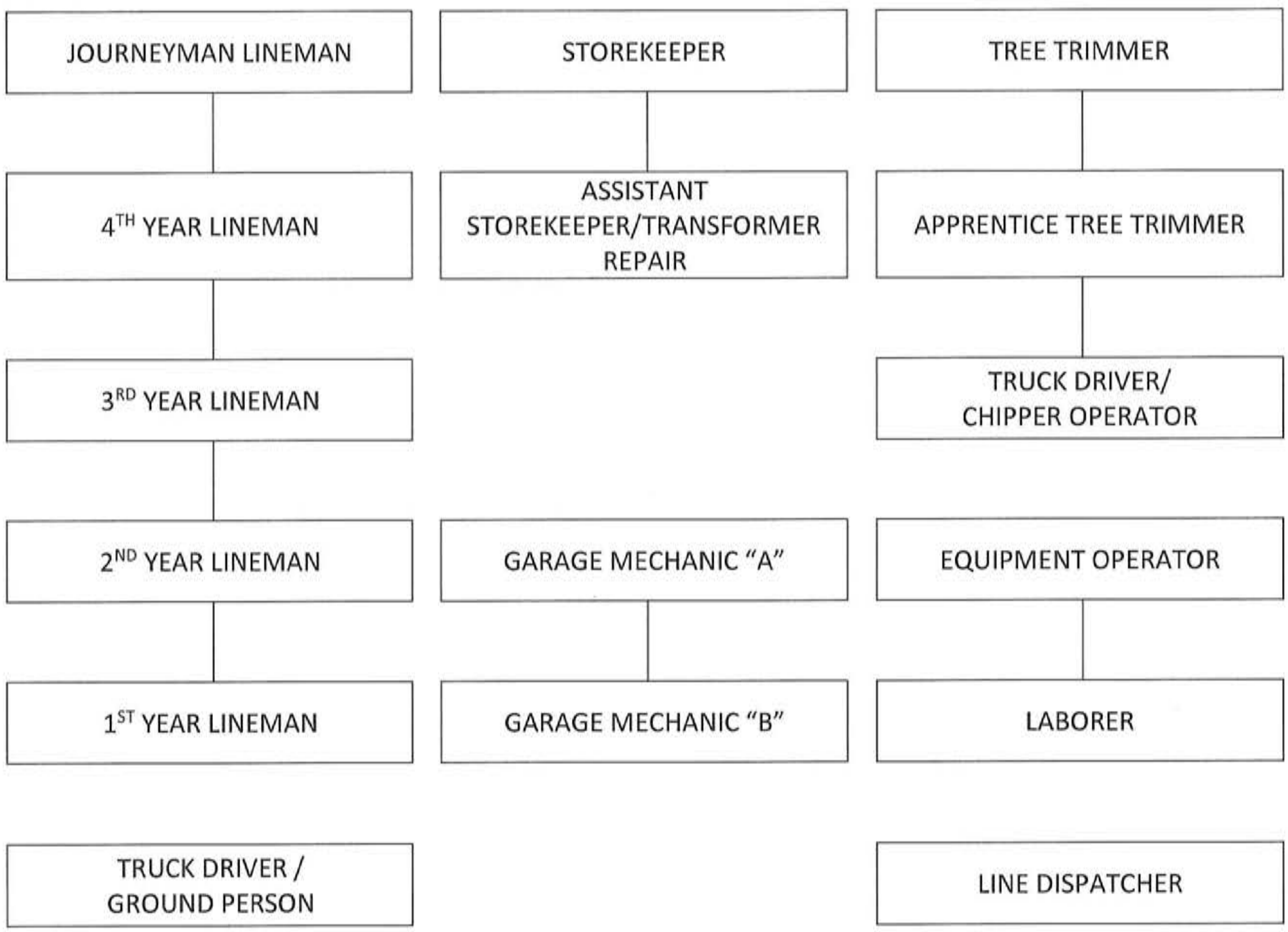
PROMOTIONAL CHART
RICHMOND POWER & LIGHT
HUMAN RESOURCES DEPARMENT

JANITOR

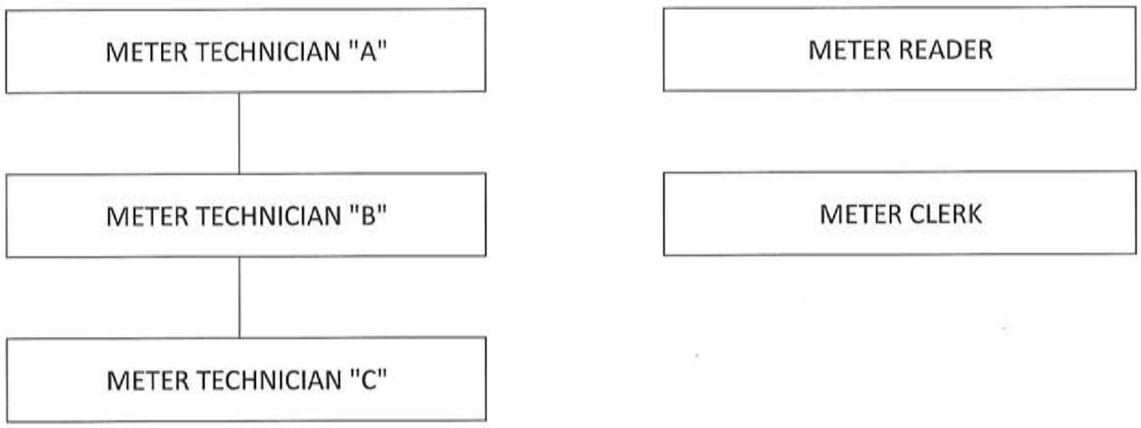
MAINTENANCE ELECTRICIAN

BUILDING MAINTENANCE – ELECTRICIAN ASSISTANT

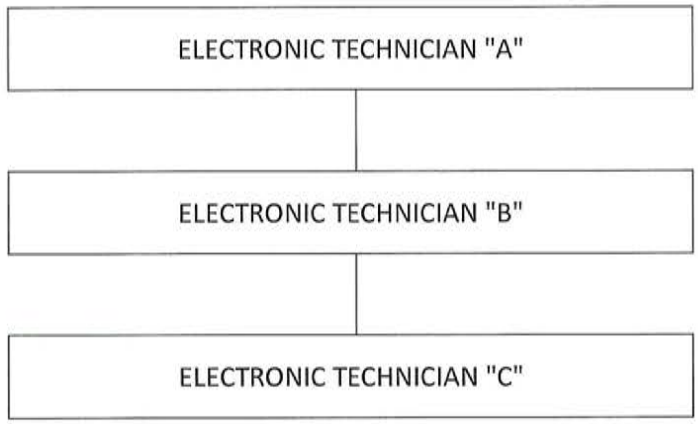
PROMOTIONAL CHART
RICHMOND POWER & LIGHT
LINE DEPARTMENT



PROMOTIONAL CHART
RICHMOND POWER & LIGHT
METER DEPARTMENT



PROMOTIONAL CHART
RICHMOND POWER & LIGHT
OPERATIONS DEPARTMENT



LETTER OF AGREEMENT

Notwithstanding any language in the contract, the parties agree that during the term of the agreement effective October 1, 2019 the Company shall not increase the percentage of employee contributions pursuant to Article 19, Sections 1 and 2. This agreement shall expire with the contract.

Dated: 02/20/2020

RICHMOND POWER & LIGHT	INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395
By: Randall D Baker	By: Mark McFarland
Randall Baker	Mark McFarland

LETTER OF AGREEMENT

During the term of the collective bargaining agreement between Richmond Power & Light and the International Brotherhood of Electrical Workers, AFL-CIO, Local 1395 which expires September 30, 2022, employees who were in the General Office on October 1, 1990, and who remain in the General Office shall have bidding rights on vacancies in classifications in the former Junior Accountant progression (now called Payroll and Audit Clerk) as if there was no line of progression for those classifications.

Dated: 02/20/2020

RICHMOND POWER & LIGHT

By: Randall Baker
Randall Baker

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395

By: Mark McFarland
Mark McFarland

LETTER OF AGREEMENT

Richmond Power & Light and International Brotherhood of Electrical Workers, AFL-CIO, Local 1395 agree that during the term of the contract between them expiring September 30, 2022, Terri L. Stephens and Amie G. Strothman shall continue to have the same bidding rights in the General Office that they had prior to their transfer to the Meter Department.

Dated: 02/20/2020

RICHMOND POWER & LIGHT

By: Randall A. Baker
Randall Baker

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395

By: Mark McFarland
Mark McFarland

LETTER OF AGREEMENT RE: INSURANCE

RPL has agreed to provide help for employees to purchase insurance who choose to retire early and who meet specific eligibility requirements. If an employee is eligible, RPL shall deposit into a health reimbursement account $800 per month to be used toward medically-qualifying expenses for the employee and/or dependents subject to the following eligibility requirements: 1) The total of the employee's age plus years of service must total 85 or the employee is age 60 and has at least 15 years of service; 2) if an employee's spouse has health insurance availability through their employment, the employee must join the spouse's coverage and RPL shall pay any premium increase imposed as a result up to $800 per month; 3)[1] the benefit described herein shall expire on the employee's 65th birthday (or upon his/her death if it occurs sooner) and shall thereafter be unavailable for the employee, spouse, and dependents; 4) if, after leaving Richmond Power and Light, the retiree becomes employed by an employer that offers any type of health insurance, the retiree, spouse, and dependents will no longer be eligible for the above-described benefit; 5) if the employee has health insurance coverage through any other source (such as disability or VA), the employee is not eligible for this benefit; and 6) the employee may elect this benefit whenever he/she meets the eligibility requirements up to the expiration date of the current collective bargaining agreement. The plan details will be included in a plan document, which is incorporated herein.

The above-described benefit will be offered through the length of the current contract. Employees that would meet the above criteria within six months of expiration of the current contract will have the option of signing a "letter of intent" by the expiration date of the current

[1] If an employee retires and is is eligible for benefits under the spousal section (number 2 above), the employee may thereafter opt for this benefit (up to the maximum of $800) if his/her spouse dies, retires, divorces, or otherwise becomes ineligible for insurance. This "opt in" provision shall be available under the spousal section.

contract to retire within six months and will thereafter be eligible subject to the foregoing criteria. The plan will expire at the end of the contract term unless agreed by the parties to continue thereafter except that any employee who elects to participate in this benefit shall continue to receive this benefit so long as they meet the eligibility requirements set forth in this letter of agreement.

The Company will ask its TPA to provide a representative to help employees understand the choices available to them and to explain the benefit, how to obtain coverage, factors to be considered, etc.

Dated: 02/20/2020

RICHMOND POWER & LIGHT	INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395
By: Randall D Baker	By: Mark McFarland
Randall Baker	Mark McFarland

LETTER OF AGREEMENT

Richmond Power & Light and International Brotherhood of Electrical Workers, AFL-CIO, Local 1395 agree that during the term of the contract between them expiring September 30, 2022, employees are eligible for 15 paid sick days per year for their own personal illness. Effective upon ratification of the contract, employees shall have the option to use 5 of the 15 paid days per year for illnesses for a child, stepchild or grandchild, spouse, and/or the employees' parent during the term of the current contract. The 5 days shall not accumulate from year to year. In other words, the employee may use a maximum of 5 days each year for other than their own personal illness as described above upon presentation of proof of illness at the request of the Company.

Dated: 02/20/2020

RICHMOND POWER & LIGHT

By: Randall D Baker
Randall Baker

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395

By: Mark McFarland
Mark McFarland

LETTER OF AGREEMENT

During the term of the Collective Bargaining Agreement between Richmond Power and Light and the International Brotherhood of Electrical Workers, AFL-CIO, Local 1395 which expires September 30, 2022, the following portion of Article 8, Section 6 "Overtime List":

> Section 6. Overtime List. …This list shall be changed every two weeks and posted on the bulletin board, with the top name rotating to the bottom of the list…..

Will be changed to:

> Section 6. Overtime List. …This list shall be changed every two weeks (with the exception of the Engineering Department whereby the list shall be changed every week) and posted on the bulletin board, with the top name rotating to the bottom of the list…..

This letter of Agreement is based on the belief that all members of the Engineering Department are in favor of this change. Should anyone in the Engineering Department express, in writing, to the Union or the Company that they no longer want this LOA to continue, then the Union or the Company will give notice to the other party of that this LOA will be terminated after 60 days' notice. In addition, the Union or the Company may give a 60 day notice, without reason, to end this agreement.

Dated: 02/20/2020

RICHMOND POWER & LIGHT	INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, LOCAL 1395
By: Randall D. Baker	By: Mark McFarland
Randall Baker	Mark McFarland

RATES AND CLASSIFICATIONS
ENERGY SERVICES

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Customer Service Clerk			
Maximum	23.96	24.68	25.42
4th 6 Mos.	23.24	23.94	24.65
3rd 6 Mos.	22.68	23.36	24.06
2nd 6 Mos.	22.06	22.72	23.41
1st 6 Mos.	21.37	22.01	22.67
Service Person			
Maximum	27.43	28.25	29.10
3rd 6 Mos.	26.69	27.49	28.31
2nd 6 Mos.	26.03	26.81	27.61
1st 6 Mos.	25.38	26.14	26.92
Energy Services Utility Person			
Maximum	23.83	24.54	25.28
4th 6 Mos.	23.23	23.92	24.64
3rd 6 Mos.	22.67	23.35	24.05
2nd 6 Mos.	21.76	22.42	23.09
1st 6 Mos.	20.92	21.55	22.19

RATES AND CLASSIFICATIONS
ENGINEERING DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Distribution Engineer 1			
Maximum	33.18	34.18	35.21
4th 6 Mos.	32.20	33.17	34.16
3rd 6 Mos.	31.27	32.21	33.18
2nd 6 Mos.	30.37	31.29	32.22
1st 6 Mos.	29.48	30.36	31.27
Distribution Engineer (Engineering Technician)			
Maximum	30.49	31.40	32.34
4th 6 Mos.	29.63	30.52	31.44
3rd 6 Mos.	28.81	229.67	30.56
2nd 6 Mos.	27.94	28.78	29.65
1st 6 Mos.	27.17	27.99	28.83
Substation Maintenance	34.05	35.07	36.12
Underground Fac Locator			
Maximum	28.33	29.18	30.06
1st 6 Mos.	27.51	28.34	29.19
Electrician "A"			
Maximum	32.92	33.91	34.93
3rd 6 Mos.	32.03	32.99	33.98
2nd 6 Mos.	31.14	32.08	33.04
1st 6 Mos.	30.22	31.13	32.06
Electrician "B"			
Maximum	28.25	29.10	29.97
3rd 6 Mos.	27.62	28.45	29.31
2nd 6 Mos.	27.10	27.91	28.75
1st 6 Mos.	26.39	27.18	28.00
Electrician "C"			
Maximum	25.73	26.50	27.30
2nd 6 Mos.	25.04	25.79	26.56
1st 6 Mos.	24.47	25.21	25.96

RATES AND CLASSIFICATIONS
ENGINEERING DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Elect. Equipment Repair Person			
Maximum	23.68	24.39	25.12
3rd 6 Mos.	22.82	23.51	24.21
2nd 6 Mos.	22.02	22.69	23.37
1st 6 Mos.	21.08	21.72	22.37

RATES AND CLASSIFICATIONS
GENERAL OFFICE

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Payroll and Audit Clerk			
Maximum	25.77	26.55	27.34
4th 6 Mos.	25.42	26.19	26.97
3rd 6 Mos.	24.98	25.73	26.50
2nd 6 Mos.	24.75	25.49	26.26
1st 6 Mos.	24.46	25.20	25.95
Accounts Payable Clerk			
Maximum	24.46	25.20	25.95
3rd 6 Mos.	24.09	24.81	25.56
2nd 6 Mos.	23.74	24.45	25.19
1st 6 Mos.	23.53	24.24	24.97
Accounts Receivable Clerk			
Maximum	23.53	24.24	24.97
3rd 6 Mos.	22.53	23.20	23.90
2nd 6 Mos.	21.51	22.16	22.82
1st 6 Mos.	20.92	21.55	22.19
Billing Clerk			
Maximum	20.92	21.55	22.19
4th 6 Mos.	20.34	20.95	21.58
3rd 6 Mos.	19.72	20.32	20.93
2nd 6 Mos.	19.12	19.69	20.28
1st 6 Mos.	18.47	19.03	19.60
Receptionist/Clerk			
Maximum	18.13	18.68	19.24
2nd 6 Mos.	17.63	18.16	18.70
1st 6 Mos.	17.16	17.68	18.21

RATES AND CLASSIFICATIONS
HUMAN RESOURCES

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Janitor			
Maximum	18.68	19.24	19.82
1st 6 Mos.	18.23	18.78	19.34
Maintenance Electrician			
Maximum	33.74	34.75	35.80
2nd 6 Mos.	32.92	33.91	34.93
1st 6 Mos.	32.03	32.99	33.98
Maintenance Electrician Asst.			
Maximum	23.61	24.32	25.05
2nd 6 Mos.	23.04	23.73	24.44
1st 6 Mos.	22.66	23.34	24.04

RATES AND CLASSIFICATIONS
IS DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Computer Operator			
Maximum	26.16	26.95	27.76
4th 6 Mos.	24.72	25.47	26.23
3rd 6 Mos.	23.83	24.54	25.28
2nd 6 Mos.	22.91	23.59	24.30
1st 6 Mos.	22.06	22.72	23.41

RATES AND CLASSIFICATIONS
LINE DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Lineman – Journeyman			
Maximum	34.05	35.07	36.12
1st 6 Mos.	32.55	33.53	34.53
Lineman – 4th year			
Maximum	31.51	32.45	33.43
1st 6 Mos.	29.69	30.58	31.50
Lineman – 3rd year			
Maximum	28.72	29.58	30.47
1st 6 Mos.	27.95	28.79	29.66
Lineman – 2nd year			
Maximum	27.26	28.08	28.92
1st 6 Mos.	26.48	27.28	28.09
Lineman – 1st year			
Maximum	25.46	26.22	27.01
1st 6 Mos.	24.96	25.71	26.48
Equipment Operator			
Maximum	28.33	29.18	30.06
1st 6 Mos.	27.51	28.34	29.19
Truck Driver - Grd Person			
Maximum	27.42	28.24	29.09
2nd 6 Mos.	26.54	27.34	28.16
1st 6 Mos.	25.68	26.45	27.24
Laborer			
Maximum	23.61	24.32	25.05
2nd 6 Mos.	23.05	23.74	24.46
1st 6 Mos.	22.66	23.34	24.04

RATES AND CLASSIFICATIONS
LINE DEPARTMENT

	1/1/2020	1/1/2021	1/1/2022
	Rate Per Hour	Rate Per Hour	Rate Per Hour
Tree Trimmer			
Maximum	29.55	30.44	31.35
2nd 6 Mos.	28.53	29.39	30.27
1st 6 Mos.	27.35	28.17	29.01
Tree Trimmer – Apprentice			
Maximum	24.33	25.06	25.81
2nd 6 Mos.	23.61	24.32	25.05
1st 6 Mos.	22.97	23.66	24.37
Truck Driver - Chipper Operator			
Maximum	26.54	27.34	28.16
1st 6 Mos.	25.21	25.96	26.74
Service Dispatcher			
Maximum	23.68	24.39	25.12
3rd 6 Mos.	22.82	23.51	24.21
2nd 6 Mos.	22.02	22.69	23.37
1st 6 Mos.	21.08	21.72	22.37
Garage Mechanic "A"			
Maximum	32.03	32.99	33.98
1st 6 Mos.	30.56	31.48	32.42
Garage Mechanic "B"			
Maximum	28.24	29.09	29.96
3rd 6 Mos.	27.33	28.15	28.99
2nd 6 Mos.	26.27	27.05	27.87
1st 6 Mos.	25.00	25.75	26.52
Storekeeper	28.74	29.60	30.49
Assistant Storekeeper/Transformer Repair	26.99	27.80	28.63

RATES AND CLASSIFICATIONS
METER DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Meter Technician "A"			
Maximum	33.03	34.02	35.04
4th 6 Mos.	32.12	33.09	34.08
3rd 6 Mos.	31.95	32.91	33.90
2nd 6 Mos.	31.38	32.32	33.29
1st 6 Mos.	30.90	31.83	32.78
Meter Technician "B"			
Maximum	28.70	29.56	30.45
3rd 6 Mos.	27.59	28.42	29.27
2nd 6 Mos.	26.95	27.76	28.60
1st 6 Mos.	26.41	27.20	28.02
Meter Technician "C"			
Maximum	26.03	26.81	27.61
2nd 6 Mos.	25.76	26.54	27.33
1st 6 Mos.	24.91	25.66	26.43
Meter Clerk			
Maximum	21.84	22.49	23.17
4th 6 Mos.	21.08	21.72	22.37
3rd 6 Mos.	20.41	21.02	21.65
2nd 6 Mos.	19.69	20.28	20.88
1st 6 Mos.	18.99	19.56	20.14
Meter Reader			
Maximum	26.88	27.68	28.51
3rd 6 Mos.	25.77	26.55	27.34
2nd 6 Mos.	24.80	25.55	26.31
1st 6 Mos.	23.82	24.53	25.27

RATES AND CLASSIFICATIONS
OPERATIONS DEPARTMENT

	1/1/2020 Rate Per Hour	1/1/2021 Rate Per Hour	1/1/2022 Rate Per Hour
Electronic Technician "A"			
Maximum	34.89	35.94	37.01
3rd 6 Mos.	33.87	34.88	35.93
2nd 6 Mos.	33.02	34.01	35.03
1st 6 Mos.	31.73	32.69	33.67
Electronic Technician "B"			
Maximum	29.71	30.60	31.52
3rd 6 Mos.	29.14	30.01	30.91
2nd 6 Mos.	28.59	29.45	30.33
1st 6 Mos.	27.96	28.80	29.67
Electronic Technician "C"			
Maximum	27.22	28.04	28.88
2nd 6 Mos.	26.65	27.45	28.27
1st 6 Mos.	26.04	26.82	27.62

Indiana Municipal Power Agency (IMPA)

2015 Integrated Resource Plan

Date Submitted:
November 2, 2015

IMPA
INDIANA MUNICIPAL POWER AGENCY

Indiana Municipal Power Agency

11610 N. College Avenue | Carmel, IN 46032
317-573-9955

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ACRONYM INDEX

AC	Alternating Current
ACEEE	American Council for an Energy-Efficient Economy
AEO	Annual Energy Outlook
AEP	American Electric Power
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ARIMA	Auto Regressive Integrated Moving Average
ASHRAE	American Society of Heating, Refrigerating and Air Conditioning Engineers
ASR	Average System Rates
BAU	Business As Usual
BSER	Best System of Emissions Reduction
BTL	Biomass To Liquids
C&I	Commercial and Industrial
CAAA	Clean Air Act Amendments
CA AB32	California Assembly Bill 32
CAFE	Corporate Average Fuel Economy
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CBO	Congressional Budget Office
CC	Combined Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CEM	Capacity Expansion Module
CEP	Community Energy Program
CFD	Carbon Fee and Dividend
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CHP	Combined Heat & Power
CO2	Carbon Dioxide
CONE	Cost of New Entry
CPNODES	Commercial Pricing Nodes
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DEI	Duke Energy Indiana
DEOK	Duke Energy Ohio
DIR	Dispatchable Intermittent Resource
DOE	U.S. Department of Energy
DSC	Debt Service Coverage
DSM	Demand-Side Management
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standard
EFOR	Effective Forced Outage Rate
EGU	Electric Generating Unit
EHVAC	Extra High-Voltage Alternating Current
EI	Energizing Indiana
EIA	Energy Information Administration
ELG	Effluent Limitations Guidelines
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency

ERC	Emission Rate Credits
EWITS	Eastern Wind Integration and Transmission Study
FDG	Flue Gas Desulfurization
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FO	Forced Outage
FOM	Fixed Operation and Maintenance
GADS	Generating Availability Data System
GB	Gigabyte
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GHz	Gigahertz
GW	Gigawatt
GWh	Gigawatt Hour
HDD	Heating Degree Days
HDV	Heavy-Duty Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
HVDC	High Voltage Direct Current
I&M	Indiana-Michigan Power Company
IBM	International Business Machines
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IOU	Investor-Owned Utility
IPL	Indianapolis Power and Light
IRC	ISO/RTO Council
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
JTS	Joint Transmission System
KW	Kilowatt
KWh	Kilowatt Hour
LDV	Light-Duty Vehicle
LFG	Landfill Gas
LG&E	Louisville Gas & Electric
LHS	Latin-Hypercube Sampling
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LRZ	Local Resource Zone
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics
MIDAS	Multi-Integrated Decision Analysis System
MILP	Mixed Integer Linear Program
MISO	Midcontinent Independent System Operator
MO	Maintenance Outage
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NAM	Nodal Algebraic Model
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation

NIPSCO	Northern Indiana Public Service Company
NITS	Network Transmission Service
NOAA	National Oceanic and Atmospheric Association
NOx	Nitrogen Oxide
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OECD	Organization for Economic Cooperative Development
OPEC	Organization of the Petroleum Exporting Countries
OTC	Over-The-Counter
OUCC	Indiana Office of Utility Consumer Counselor
PADD	Petroleum Administration for Defense Districts
PC	Personal Computer
PJM	Pennsylvania-New Jersey-Maryland
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PSEC	Prairie State Energy Campus
PSGC	Prairie State Generating Company
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements
RAM	Random Access Memory
RAR	Resource Adequacy Requirement
RCRA	Resource Conservation and Recovery Act
RES	Renewable Energy Standard
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCED	Security-Constrained Economic Dispatch
SCR	Selective Catalytic Reduction
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SPSS	Statistical Package and Service Solutions
T&LF	Transmission and Local Facilities Agreement
TDU	Transmission Dependent Utility
TO	Transmission Owner
TPA	Third Party Administrator
TW	Terawatt
TWh	Terawatt Hour
UCAP	Unforced Capacity
VMT	Vehicle Miles Traveled
VOM	Variable Operation and Maintenance
VRR	Variable Resource Requirement
WVPA	Wabash Valley Power Association
WWVS	Whitewater Valley Station

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1 EXECUTIVE SUMMARY

The Indiana Municipal Power Agency (IMPA) is a wholesale electric utility serving the total electricity requirements of 60 communities under long term power sales contracts. Each of IMPA's 59 members is an Indiana city or town with a municipally owned electric distribution utility. IMPA also serves the Village of Blanchester, Ohio. IMPA regularly reviews its projected loads and resources in order to ensure it is planning to meet its member's long term load requirements in an economical, reliable and environmentally responsible manner. These planning activities are required under IMPA's risk management framework and are necessary to participate in the Regional Transmission Organization (RTO) markets. Pursuant to the requirements of 170 IAC 4-7, IMPA presents its 2015 Integrated Resource Plan (IRP). This report assesses IMPA's options to meet its members' capacity and energy requirements for wholesale service from 2016 through 2035.

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

In 2015, IMPA's coincident peak demand for its 60 communities was 1,163 MW, and the annual energy requirements during 2014 were 6,225,553 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has not added any new members.

IMPA currently uses both supply and demand-side resources to meet its customer peak demand and energy requirements. Current resources include:

- Joint ownership interests in Gibson Station #5, Trimble County Station #1 & #2 and Prairie State Energy Campus #1 and #2;
- Operate and maintain Whitewater Valley Station #1 & #2;
- Five (5) gas fired combustion turbines owned and operated by IMPA;
- Two (2) gas fired turbines owned by IMPA and operated by Indianapolis Power and Light (IPL);
- Generating capacity owned by one (1) IMPA member;
- Nine (9) Solar Parks located in member communities
- Long term power purchases from:
    - Indiana-Michigan Power Company (I&M)
    - Duke Energy Indiana (DEI)
    - Crystal Lake Wind, LLC
- Short term contracts with market participants in MISO and/or PJM;
- Energy Efficiency Program

IMPA's existing resources are diverse in terms of size, fuel type and source, geographic location and vintage. IMPA owns or controls generation in MISO and PJM as well as in the Louisville Gas

& Electric/Kentucky Utilities (collectively LG&E) control area. In total, IMPA's generation and contractual resources reside in eight (8) different load zones in Indiana, Illinois, Iowa and Kentucky. This diversity reduces IMPA exposure to forced outages, locational marginal prices (LMPs), zonal capacity rates and regional fuel costs.

IMPA's energy efficiency program offers incentives in the form of rebates for residential and commercial and industrial (C&I) customers. Since 2009, IMPA's energy efficiency efforts have saved approximately 11.3 MW (coincident peak) and 104,175 MWh. In addition to its energy efficiency program, IMPA offers a demand response tariff, a net metering tariff, energy audits, education and training and many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption.

As discussed in the body of this report, IMPA has considered a variety of potential supply and demand-side resources. These are discussed more fully in Section 6. IMPA's analysis has identified a plan that allows it to economically meet its members future load growth while limiting future risks due to unforeseen legal or regulatory outcomes. The description of the modeling and planning process/selection is discussed in Sections 10-16.

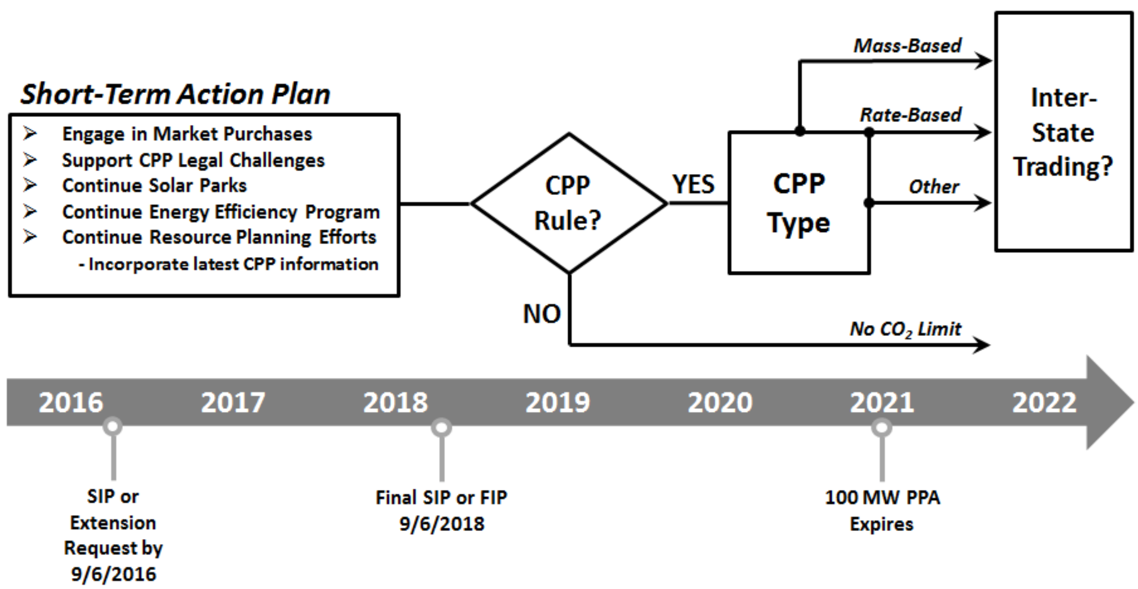
1.1 Action Plan

While IMPA has a need for capacity and energy over the next 5 years (2016-2020); those needs will be fulfilled through market purchases as the positions are relatively small. IMPA's next resource decision comes in 2021 when a 100 MW PPA expires. IMPA's Status Quo Plan (Plan01) calls for a 500 MW participation share in combined cycle unit(s) coupled with the retirement of Whitewater Valley Station (WWVS) units #1 and #2. In the development of Plan01, it was assumed the Environmental Protection Agency's (EPA) Clean Power Plan (CPP) is not implemented as it is neither known nor measureable at this point in time. The WWVS retirement was also assumed, not because it is imminent, but merely because it is the output of an optimization run under status quo conditions.

IMPA developed three additional plans (Plan03, Plan04, and Plan05) to address the impact of the carbon emission limits set forth in the CPP rule. IMPA's action plan is to delay, to the extent practical, its next resource decision to allow time for more clarity on the CPP rule. IMPA understands it ultimately may need to make its next resource decision with the best information it has at the time as the CPP legal challenges may take years to settle and will likely reach the U.S. Supreme Court. As a CPP hedge, IMPA's strategic plan is to continue its Solar Park installation program where 10 MW of solar is added to IMPA member distribution systems annually.

The following diagram illustrates the Plan Pursuit strategy:

Figure 1 Plan Pursuit Strategy (2016-2022)



As shown in the diagram above, even if the CPP rule is upheld, there are a number of questions to be answered which will affect IMPA's next resource decision. Is the CPP massed-based, rate-based or something else? IMPA has generation in Indiana, Illinois, and Kentucky. Will the states have similar plans which allow inter-state trading or will each state be unique? How do natural gas, energy efficiency and renewables fit into the mix?

At this time, IMPA is not proposing the acquisition of any specific resource. IMPA will continue to evaluate resource options matching this plan and bring any firm proposals requiring IURC approval before the Commission at the appropriate time.

In the absence of a CPP rule, IMPA's preferred resource expansion plan is shown below. The retirement of WWVS in 2022 is not imminent, but merely reflects the output of an optimization run under status quo conditions.

Table 1 2015 IRP Expansion Plan – Plan01

	Capacity Losses		Capacity Additions		
Year	MW Lost	Resource	MW Added	Resource	Net MW
2016	(5)	PPA Expires	10	Solar	5
2017	(69) (6)	PPA Expires Member Gen Retires	10 100	Solar PPA	35
2018	(50)	PPA Expires	10	Solar	(40)
2019			10	Solar	10
2020			10	Solar	10
2021	(100)	PPA Expires	200	Advanced CC	100
2022	(90)	WWVS Retires	100	Advanced CC	10
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	200	Advanced CC	10
2035					
Total	(510)		650		140

2 IMPA OVERVIEW

2.1 INTRODUCTION

Pursuant to the provisions of Indiana Code § 8-1-2.2-1 *et seq*., IMPA was created in 1980 for the purpose of undertaking the planning, financing, ownership and operation of projects to supply electric power and energy for the present and future needs of the members. IMPA is the full requirements power provider to its wholesale customers. While IMPA's member/customers serve a population in excess of 325,000 people, IMPA has no retail customers itself. IMPA has entered into separate power sales contracts to supply 100% of its wholesale customer's electric power and energy requirements.

In addition to increasing its membership/customers from the initial 24 to 60 cities and towns, major milestones in IMPA's history include:

Table 2 Major IMPA Milestones

Date	Milestone
Fall 1982	Acquired an ownership share of Gibson Unit 5
Winter 1983	Began power supply operations to 24 members
Fall 1985	Acquired an ownership share of the Joint Transmission System (JTS)
Spring 1992	Placed Richmond Combustion Turbine Units 1 and 2 into commercial operation
Summer 1992	Placed Anderson Combustion Turbine Units 1 and 2 into commercial operation
Fall 1993	Acquired an ownership share of Trimble County Unit 1
Spring 2004	Placed Anderson Combustion Turbine Unit 3 into commercial operation
Fall 2004	Acquired Units 2 and 3 of the Georgetown Combustion Turbine Station
Fall 2008	Signed Crystal Lake wind energy purchased power agreement
Winter 2011	Placed Trimble County Unit 2 into commercial operation
Summer 2012	Placed Prairie State Unit 1 into commercial operation
Fall 2012	Placed Prairie State Unit 2 into commercial operation
Summer 2014	Placed Frankton, Rensselaer and Richmond solar parks into commercial operation
Summer/Fall 2015	Placed Tell City, Crawfordsville, Peru, Pendleton, Argos and Bainbridge solar parks into commercial operation

2.2 Recent Activities – Key Events Since Last IRP

Since IMPA submitted its last Integrated Resource Plan to the IURC on November 1, 2013, the following events have taken place:

- On January 1, 2014, IMPA exited its voluntary involvement with Energizing Indiana, replacing it with the self-managed Energy Efficiency program.
- On June 23, 2014, the Frankton solar park was placed in commercial operation.
- On July 14, 2014, the Rensselaer solar park was placed in commercial operation.
- On September 18, 2014, the Richmond solar park was placed in commercial operation.
- On October 31, 2014, IMPA closed on the sale of its Power Supply System Refunding Revenue Bonds, 2014 Series A. The purpose of these bonds was to advance refund outstanding bonds at lower interest rates.
- On March 16, 2015, IMPA and Duke Energy Indiana entered into a 100 MW contract for capacity and energy with a term from June 1, 2017 – May 31, 2021.
- On July 7, 2015, the Tell City solar park was placed in commercial operation.
- On August 28, 2015, IMPA dedicated the new IMPA conference center at IMPA's Carmel, IN campus.
- On August 19, 2015, the Peru solar park was placed in commercial operation.
- On September 3, 2015, the Crawfordsville solar park was placed in commercial operation.
- In the fall of 2015, Pendleton, Argos and Bainbridge solar parks were placed in commercial operation.

3 IRP OBJECTIVES AND PROCESS

3.1 IRP RULES (170 IAC 4-7)

The IURC developed guidelines in 170 IAC 4-7-1 *et seq*. for electric utility IRPs in order to assist the IURC in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5. IMPA and seven other utilities across the state of Indiana are subject to the IRP rules. Section 18 of this IRP summarizes the rules, along with an index of IMPA's responses to those rules.

3.2 IMPA IRP OBJECTIVES

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

3.3 IMPA PLANNING CRITERIA

IMPA serves wholesale load in both MISO and PJM and must comply with the resource adequacy requirements of each RTO for its load in that RTO. In its planning process, IMPA utilizes the same UCAP and EFOR method of resource compliance as used in the RTOs. For this IRP, IMPA utilized the most recently available resource planning requirement figures for PJM and MISO. With IMPA's EFOR rates and the combined reliability requirements of PJM and MISO, IMPA's traditionally calculated reserve margin target equates to approximately 15%.

IMPA plans its resources to meet its projected load and does not allow the expansion models to add resources for non-member or speculative sales. IMPA does allow the model to purchase some market capacity in the future, but these are limited to small quantities (<100 MW) and meant to simulate the normal final balancing that takes place in today's RTO capacity markets. This buffer also allows flexibility in the future regarding load uncertainty, energy efficiency, demand response and renewables development.

3.4 IMPA PLANNING PROCESS

Formulating an IRP is a multistep project that utilizes many disciplines including engineering, environmental science, statistics and finance. The basic steps of the IRP process are summarized below, with references to where further information can be found in this document.

1. Evaluation of Existing System – Establishes the basis for future resource planning by identifying the expected future availability of existing supply-side and demand-side resources, including possible upgrades, expansions or retirements of those resources. (Section 4)

2. Long Range Forecast Development – Annually, IMPA develops a 20-year projection of peak demands and annual energy requirements. The load forecast is developed using a time-series, linear regression equation for each load zone. (Section 5)

3. Resource Options and Environmental Compliance – This step involves the selection and screening of various supply-side and demand-side alternatives. Additionally,

transmission service and compliance with future environmental issues are discussed. (Sections 6-8)

4. Software Overview / Data Sources – This section describes the software and data sources used to perform the analysis. (Section 9)

5. Scenario Development – IMPA creates scenarios as a structured way to think about the future as scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. IMPA stakeholders develop stories about how the future might unfold by iteratively building plausible alternate views of the future given different economic, regulatory, and technological driving forces. (Section 10)

6. Evaluation of Resource Alternatives and Resource Optimization – Integrating the alternatives into a common tool used to optimally select and evaluate various scenarios is a key part of the IRP process. IMPA uses a multi-part modeling system consisting of a wholesale market model, a capacity expansion model and a system dispatch and finance model. (Sections 11-13)

7. Plan Evaluation – A crucial part of the IRP process is evaluating how a portfolio performs under various stochastic drivers and its sensitivity to movements of certain variables. (Section 14-15)

8. Plan Selection – Description of preferred plan and basis for selection. (Section 16)

9. Short Term Action Plan – Description of steps necessary to implement the preferred plan. (Section 17)

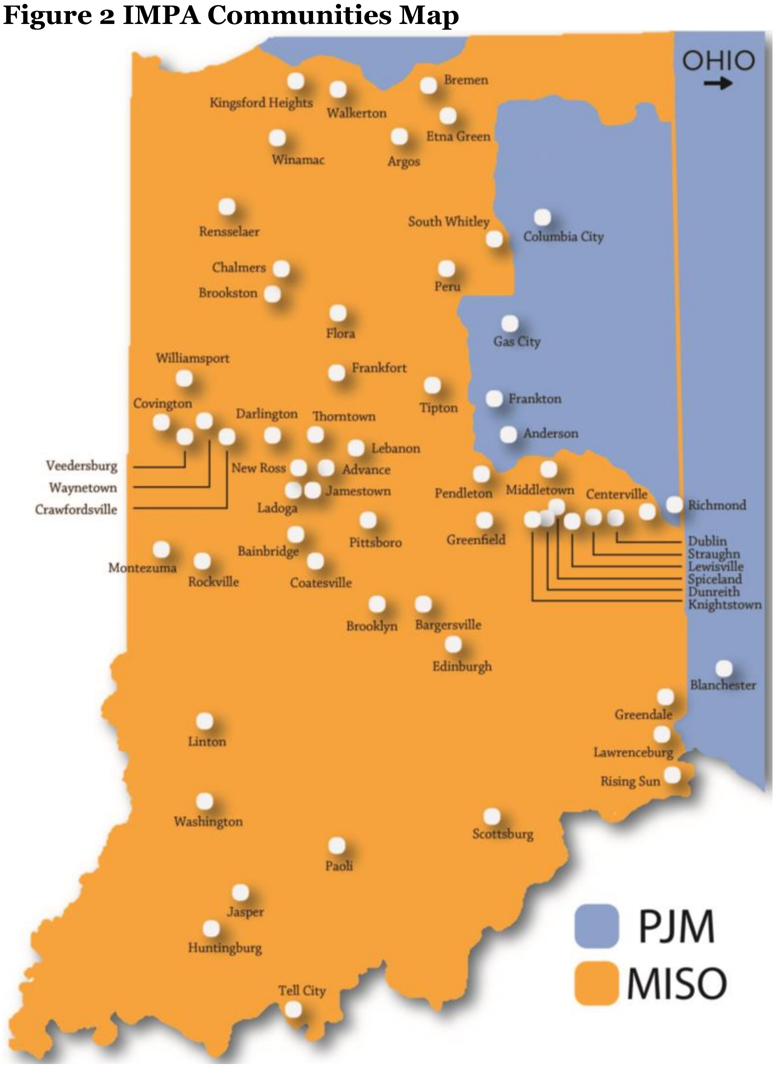
4 EXISTING SYSTEM

4.1 IMPA System Description

IMPA is a wholesale electric utility serving the total electricity requirements of 60 communities. Each of IMPA's 59 members is an Indiana city or town with a municipally owned electric distribution utility. IMPA also serves the Village of Blanchester, Ohio on a full-requirements contractual basis very similar to its member contracts, except for specific provisions applicable to Indiana municipalities (the most significant being that Blanchester does not have a seat on IMPA's Board of Commissioners). IMPA has no retail customers and no direct communication or other interaction with the member's retail customers, except as specifically requested by the member.

IMPA operates in both the MISO and PJM RTOs. IMPA has load in five IOU load zones and generation resources connected to seven IOU zones within the RTO footprints, plus two resources outside of the RTOs. IMPA's load is divided approximately 2/3 MISO and 1/3 PJM.

Figure 2 IMPA Communities Map



4.2 LOADS AND LOAD GROWTH

IMPA's member and customer communities are located in five different load zones in MISO and PJM. When IMPA began operations in 1983, it served 24 communities. IMPA now serves 60 communities. The following table lists the 60 communities that IMPA serves along with the load zone, RTO in which they are located and the approximate percentage of IMPA's total load.

Table 3 IMPA Communities

RTO	Load Zone	% of Load	Community
MISO	Duke-IN	51%	Advance, Bainbridge, Bargersville, Brooklyn, Centerville, Coatesville, Covington, Crawfordsville, Darlington, Dublin, Dunreith, Edinburgh, Flora, Frankfort, Greendale, Greenfield, Jamestown, Knightstown, Ladoga, Lawrenceburg, Lebanon, Lewisville, Linton, Middletown, Montezuma, New Ross, Paoli, Pendleton, Peru, Pittsboro, Rising Sun, Rockville, Scottsburg, South Whitley, Spiceland, Straughn, Thorntown, Tipton, Veedersburg, Washington, Waynetown, Williamsport
	NIPSCO	7%	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Rensselaer, Walkerton, Winamac
	VECTREN	10%	Huntingburg, Jasper, Tell City
PJM	AEP-IM	31%	Anderson, Columbia City, Frankton, Gas City, Richmond
	Duke-OH	1%	Blanchester, Ohio

In 2015, IMPA's peak demand for its 60 communities was 1,163 MW, and the annual energy requirements during 2014 were 6,225,553 MWh.

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA as a whole are shown in Appendix B. As a wholesale supplier, IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance.

4.3 Existing Supply-Side Resources

IMPA currently has a variety of supply-side resources, including: ownership interests in Gibson Unit 5, Trimble County Units 1 and 2, Prairie State Units 1 and 2; operation and maintenance responsibilities for Whitewater Valley Units 1 and 2; seven combustion turbines wholly owned by IMPA; solar parks located in several different member communities; generating capacity owned and operated by one of IMPA's members; long-term firm power purchases from I&M and DEI, as well as short term purchases from various utilities and power marketers in the MISO and PJM energy markets. In 2008, IMPA signed a purchased power agreement for up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. The expected renewable energy from this contract will meet approximately 2.5% of IMPA's energy needs. Some of these resources, such as firm power purchases, have contractual limitations that restrict their use to a particular local balancing area or delivery point. Tables summarizing the key characteristics of IMPA's generating units and long term purchased power agreements are shown in Appendices E1 and E2. The resources and contracts are described in more detail on the following pages.

Gibson 5

IMPA has a 24.95% undivided ownership interest in Gibson 5, which it jointly owns with DEI (50.05%) and Wabash Valley Power Association (WVPA) (25.00%). Gibson 5 is a 625-MW coal-fired generating facility located in southwestern Indiana. It is equipped with particulate, SO_2 and NO_x removal facilities (SCR system) and an SO_3 mitigation process. The boiler has also been retrofitted with low NO_x burners. Fuel supply for Gibson Station is acquired through a number of contracts with different coal suppliers. The coal consists of mostly high sulfur coal sourced from Indiana and Illinois mines. A small amount of low sulfur coal is also purchased. DEI has multiple coal contracts of varying lengths to supply the five units at Gibson Station. Procurement is such that the prompt year's supply is nearly completely hedged while future years are partially contracted two to three years in advance. Coal is delivered by both train and truck. The current targeted stockpile inventory is 45-60 days.

DEI operates Gibson 5 under the "Gibson Unit No. 5 Joint Ownership, Participation, Operation and Maintenance Agreement" (Gibson 5 Agreement) among DEI, IMPA and WVPA. The Gibson 5 Agreement obligates each owner to pay its respective share of the operating costs of Gibson 5 and entitles each owner to its respective share of the capacity and energy output of Gibson 5.

Trimble County 1

IMPA has a 12.88% undivided ownership interest in Trimble County 1, which is jointly owned with LG&E (75.00%) and the Illinois Municipal Electric Agency (IMEA) (12.12%). Trimble County 1 is a 514-MW coal-fired unit located in Kentucky on the Ohio River approximately 15 miles from Madison, Indiana. The unit is equipped with particulate, SO_2 and NO_x removal facilities and an SO_3 mitigation process. The boiler burners have been modified to meet the NO_x limits of Phase II of the Acid Rain Program. To date, IMPA's share of the SO_2 and NO_x emissions allowances allocated by EPA and the Kentucky Energy and Environment Cabinet have satisfied IMPA's requirements for such allowances. Trimble County 1 burns high sulfur coal. LG&E purchases coal on a system basis and delivers it on an economic basis to its various power plants. The majority of this coal is from mines in Indiana and Kentucky. All coal is delivered to Trimble County by barge. Due to barge delivery, stockpile inventory levels fluctuate within a targeted 28-49 day level.

LG&E operates Trimble County 1 under the "Participation Agreement By and Between LG&E, IMEA and IMPA" (Trimble County 1 Agreement). The Trimble County 1 Agreement obligates each owner to pay its respective share of the operating costs of Trimble County 1 and entitles each owner to its respective share of the capacity and energy output of Trimble County 1. Transmission service is provided from the plant to the LGEE-MISO interface.

Trimble County 2

IMPA constructed Trimble County 2 jointly with LG&E and IMEA. Commercial operation commenced in January 2011. Trimble County 2 is a 750 MW (net) unit with a supercritical, pulverized coal boiler and a steam-electric turbine generator. Unit 2 is equipped with low-NO_x burners, an SCR system, a dry electrostatic precipitator, pulse jet fabric filter, wet flue gas desulfurization, and a wet electrostatic precipitator. The coal is eastern bituminous coal (including, potentially, Indiana coal) blended with western sub-bituminous coal. All coal arrives at the site via barge on the Ohio River. LG&E uses the same procedures for selection and delivery of coal to Trimble County 2 as it uses for Trimble County 1. Trimble County 2 flue gas exhausts through two new flues in the existing site chimney.

The ownership arrangement for Trimble County 2 has the same undivided ownership percentages as for Trimble County 1: LG&E at 75%, IMPA at 12.88% and IMEA at 12.12%. LG&E is acting as operating agent for the owners under a Participation Agreement similar to that used to operate Trimble County #1. Transmission service is provided from the plant to the LGEE-MISO interface.

Prairie State Project

The Prairie State Energy Campus (PSEC) consists of the Prairie State Units #1 & #2, related electric interconnection facilities, the Lively Grove mine, the near-field coal combustion residuals (CCR) disposal facility, and the Jordan Grove CCR disposal facility. IMPA is part of a consortium of organizations that collectively direct the Prairie State Generating Company (PSGC) in operating the PSEC. IMPA has a 12.64% interest in the Prairie State Project. Both units began commercial operation in 2012.

Prairie State is in the southwest part of Washington County, Illinois, approximately 40 miles southeast of St. Louis, Missouri. The plant includes two steam-electric turbine generators totaling approximately 1,600 MW. The plant's two boilers are supercritical, pulverized coal steam generators with low-NO_x burners, SCR systems, dry electrostatic precipitators, wet flue gas desulfurization and wet electrostatic precipitators.

The project also includes contiguous coal reserves owned by the project participants to supply Illinois coal to the power plant. PSGC estimates the project-owned coal reserves will supply the coal required by the plant for approximately 30 years. PSGC owns or controls 100% of the surface property around the mine portal.

IMPA Combustion Turbines

IMPA has seven wholly-owned combustion turbines. Three units are located in Anderson, Indiana (Anderson Station), two units are located near Richmond, Indiana (Richmond Station), and two units are located at the Georgetown Combustion Turbine Station in Indianapolis, Indiana (Georgetown Station).

IMPA operates and maintains the Anderson and Richmond Stations with on-site IMPA personnel. The original four machines are GE-6Bs and Anderson Unit #3 is a GE-7EA. These units operate primarily on natural gas, with No. 2 fuel oil available as an alternate fuel. Natural gas is delivered under an interruptible contract with Vectren. This contract gives IMPA the option to obtain its own gas supplies from various sources with gas transportation supplied by Vectren. IMPA maintains an inventory of No. 2 fuel oil at each station.

IMPA is the sole owner of Units 2 and 3 at the Georgetown Station. Indianapolis Power & Light (IPL) operates these two units on behalf of IMPA. The units are both GE-7EA machines and are gas fired. Citizens Gas delivers the gas to the Station from the Panhandle Eastern pipeline system. IPL has the responsibility to ensure IMPA's units comply with applicable environmental requirements.

IMPA Solar Parks

In 2013, IMPA began a program to construct small PV solar parks in member communities. By the end of 2015 nine (9) facilities totaling 13 MW will be in service. These solar parks range in size from .3 to 3 MW and are connected to member distribution systems. An additional 10 MW of parks are in development for commercial operation in 2016.

Member-Owned Capacity

IMPA members Rensselaer and Richmond own generating facilities. The following paragraphs briefly describe those member facilities.

Rensselaer's generating plant consists of six internal combustion engines with a total tested capability of approximately 18 MW. Four of the six machines are designed to operate on natural gas and No. 2 diesel fuel oil. Unit 5 can operate on diesel only and Unit 15 on natural gas only. Units 6, 10 and 11 are currently operated on No. 2 fuel oil only. Unit 14 is dual fuel capable and burns natural gas as a primary fuel with fuel oil available as a backup.

The Rensselaer generating plant is exempt from the Title IV Acid Rain provisions of the CAAA, CAIR and CSAPR requirements since all the units are under 25 MW. Unit 5 has been reclassified as an "emergency unit" for compliance with the RICE Rule. This means Unit 5 can be operated for emergency use only and is not considered a capacity resource. For purposes of this IRP, the diesel units are retired at the end of 2016, though no definitive announcements have been made on the retirement of these units.

On June 1, 2014 IMPA entered into an amended and restated capacity purchase agreement with Richmond Power & Light, obtaining the rights to operate and maintain the Whitewater Valley Station (WWVS). WWVS consists of two coal-fired generating units with a current maximum tested capability of approximately 30 MW and 60 MW, respectively. IMPA purchases coal on a short-term and spot market basis to support operation of the plant which is generally used to fulfil peaking needs.

Firm Power Purchases

On January 1, 2006, IMPA began taking firm power and energy from I&M under a "Cost-Based Formula Rate Agreement for Base Load Electric Service." Initially, this agreement provided IMPA with base load power and energy for a twenty-year period. The initial contract quantity under this agreement was 150 MW. IMPA may increase its purchases by up to 10 MW each year to a maximum delivery of 250 MW. The current contract quantity is 190 MW. I&M's demand and energy charges are calculated each year according to a formula that reflects the previous year's costs with an annual "true-up" the following year. I&M is responsible for providing the capacity reserves under this contract. The contract was extended in 2010 and now has an expiration date of May 31, 2034.

On June 1, 2007, IMPA began taking firm power and energy from DEI under a "Power Sale Agreement for Firm Energy and Capacity." This agreement provides IMPA with 50 MW of base load power and energy. DEI recalculates its demand and energy charges each year according to a formula that reflects the previous year's costs with an annual reconciliation. DEI is responsible for providing the capacity reserves under this contract. This contract expires May 31, 2017.

Upon the expiration of the DEI contract discussed above, a new 100 MW contract with DEI begins. The new contract provides dispatchable energy with minimum annual loading requirements. The demand charge is a negotiated fixed rate while the fuel charge is a cost based formula. The contract expires on May 31, 2021.

Throughout 2012, IMPA entered into long-term power supply agreements with six former DEI wholesale customers; Veedersburg, Coatesville, Williamsport, South Whitley, Montezuma and New Ross. As part of the agreement with the customers, their preexisting full requirements contracts with DEI were assumed by IMPA. Initially these contracts had expiration dates between 2015 and 2021. As part of the negotiated new DEI contract discussed previously, the remaining contracts (four) terminate on May 31, 2017.

Other Power Purchases

On October 7, 2008, IMPA entered into a contract with Crystal Lake Wind, LLC for the purchase of up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. Deliveries under the contract commenced on November 15, 2008. The contract expires December 31, 2018.

IMPA has entered into various monthly purchased power contracts with multiple counterparties to supplement the power and energy available to it from other resources. IMPA engages in both physical and financial transactions for capacity and energy. IMPA currently has short term market capacity and/or energy deals extending out as far as six years.

Green Power

IMPA offers a Green Power rate to its members, for pass through to their retail customers. Under this rate, IMPA will obtain and provide green power for a small incremental cost over its base rate. As discussed above, IMPA currently owns 13 MW of solar facilities and has a contract for the purchase of 50 MW of wind energy.

IMPA members implement the Green Power rate if they desire. Currently, IMPA members have 28 retail customers on the Green Power rate.

Net Metering Tariff

On January 28, 2009 the Board approved IMPA's net metering tariff. This tariff allows for the net metering of small renewable energy systems at retail customer locations. As with the Green

Power rate, the net metering tariff is implemented at the member's discretion. At this time, IMPA knows of 15 net metering installations in its members' service territories.

IMPA has been approached by customers wishing to install larger renewable systems that exceed the maximum size allowed under the net metering tariff. IMPA's preferred method of handling these large systems is to sign a contract to purchase the power as is done with the industrial customers referenced below. At this time, there are no larger renewable installations taking advantage of this offer.

Retail Customer-Owned Generation

IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate.

IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems would be beneficial to both the customer and the Agency, the very site specific operating conditions and economics must be in place for both parties in order for a CHP project to go forward.

With the exception of emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories.

4.4 EXISTING DEMAND-SIDE RESOURCES

Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members. A discussion of existing programs is provided below.

IMPA Streetlight Upgrades Program

IMPA, on behalf of its participating communities, was one of 20 grant applicants selected from around the country in June 2010 to receive a Department of Energy (DOE) Energy Efficiency and Conservation Block Grant through the American Recovery and Reinvestment Act. IMPA was awarded $5 million on behalf of its members to implement local streetlight retrofitting programs in the Agency's member communities.

The original plan called for the replacement or retrofit of approximately 6,800 streetlights with an estimated annual savings of approximately 3.4 million kilowatt hours (kWh) collectively for 19 participating communities. The plan also went one step further with all the communities involved agreeing to set aside 50 percent of the financial savings realized as a result of reduced power usage to fund future energy efficient improvements in the community.

The street light selection process was so successful that IMPA was able to extend the original plan from approximately 19 communities, 6,800 lights and 3.4 million kilowatt-hours of savings to 32 communities, approximately 11,000 lights and 6.1 million kilowatt-hours of savings. Over the course of 2011, the participating communities replaced and retrofitted their existing streetlights with the new energy efficient lights. IMPA, with its team of participating communities, was the first grant recipient to complete its project under this DOE grant program. In 2012, the program was extended to several more communities resulting in an additional 5.5 million kilowatt-hours of savings.

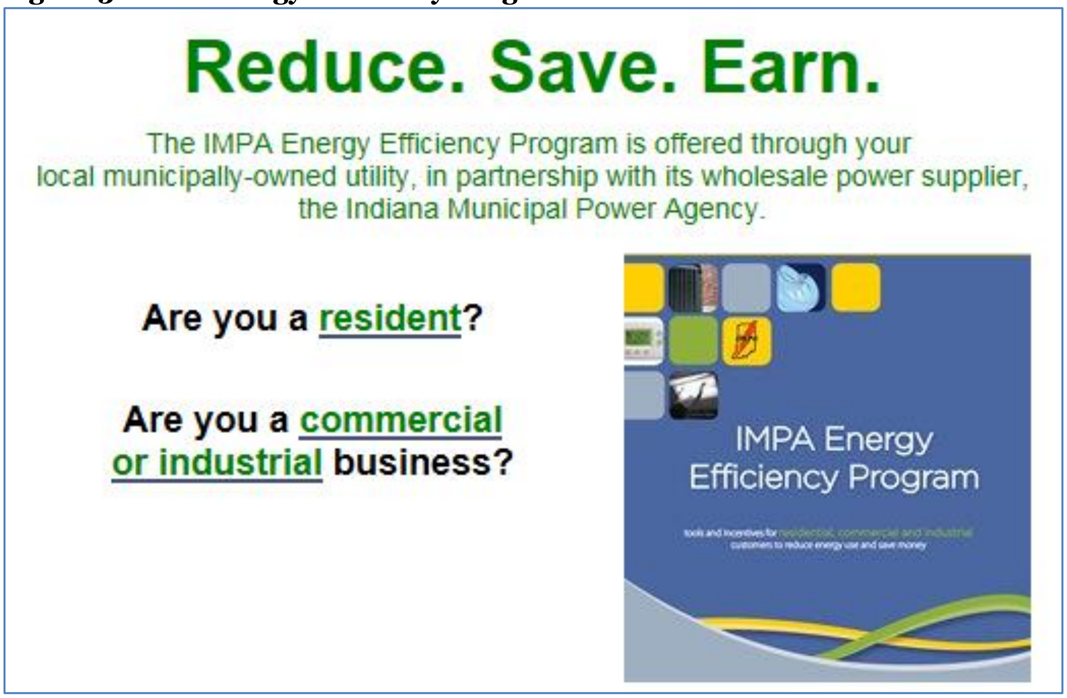
IMPA Energy Efficiency Program

In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help commercial and industrial customers in the Agency's 59 member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting; heating, ventilation and air conditioning; motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers and build relationships with local vendors to implement the energy saving measures. During 2011, the Agency as a whole saw approximately 90 companies participate in the program, representing 25 member communities throughout the state of Indiana. The cumulative savings from these efficiency efforts is 7.6 million kWh annually. If an average home consumes 12,000 kWh per year, then the program has effectively reduced the amount of energy required to power over 633 homes.

In 2012 and 2013, IMPA voluntarily participated in the Indiana state-wide core program referred to as Energizing Indiana (EI) to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts is 32 million kWh (2012) and 52.7 million kWh (2013), annually.

In 2014, IMPA returned to the more cost-effective, self-managed energy efficiency program, which it first launched in 2011, and exited the Energizing Indiana program. IMPA added residential rebates for HVAC in addition to its menu of C&I rebates. The link to the IMPA Energy Efficiency website is shown below.

Figure 3 IMPA Energy Efficiency Program



Source: http://www.impa.com/energyefficiency

Community Energy Program (CEP)

During 2011, IMPA also assisted member communities in applying for the opportunity to participate in a Community Energy Program (CEP) offered through the Indiana Office of Energy Development. Eight members were awarded with CEP-provided energy audits of the public facilities in their communities and personalized strategic energy plans with both short and long-term energy efficiency goals.

The program included an inventory of all energy usage at public facilities in the city, a full energy audit to identify potential energy saving measures, an established baseline for utility bills, a list of short and long-term energy goals for the community, suggestions to streamline energy decision-making and purchasing processes, ideas for funding energy efficiency projects, as well as a public meeting to inform the entire community about the new, comprehensive energy plan. The CEP was funded through the Energy Efficiency and Conservation Block Grant Program, the same program that provided funds for the street lighting effort.

Energy Efficiency and Conservation Education

IMPA has long promoted energy efficiency and conservation in its member communities. IMPA includes such information, developed both from public and internal sources, in the Municipal Power News, a publication which IMPA mails to members' customers' homes and businesses three times each year. The Agency also provides literature containing conservation and efficiency tips to member communities for distribution in their local utility offices or events.

Each issue of Municipal Power News includes a small energy efficiency quiz. Customers may enter their answers in a drawing at IMPA. Correct responders are mailed a small energy efficiency kit consisting of CFLs, weather stripping, outlet insulators and energy savings tips. IMPA has distributed approximately 700 of these kits through this and other delivery mechanisms.

IMPA's website at www.impa.com includes energy efficiency, conservation and safety information for consumers as well as providing the APOGEE online energy audit application, as discussed below. These new web pages include conservation tips, renewable and environmental information, and safety facts, as well as links to energy websites like Energy Star® and the U.S. Department of Energy.

IMPA staff also assists its members and their customers by providing walk-through energy audits and recommendations for power factor improvements to individual industrial customers.

Compact Fluorescent Light (CFL) Rebate Program

In the fall of 2008, IMPA began distributing CFL rebates in its communities. Working in conjunction with General Electric, IMPA distributed coupons worth $1 off any package of CFL bulbs. With the planned Statewide TPA implementation date of January 1, 2011, this program ended in 2010 with the last distribution of coupons occurring in the summer of 2010.

Demand Response

On December 10, 2010, IMPA's board approved Demand Response tariffs in order to utilize demand response programs offered under the MISO and PJM tariffs. At this time, no customers have signed up for the program.

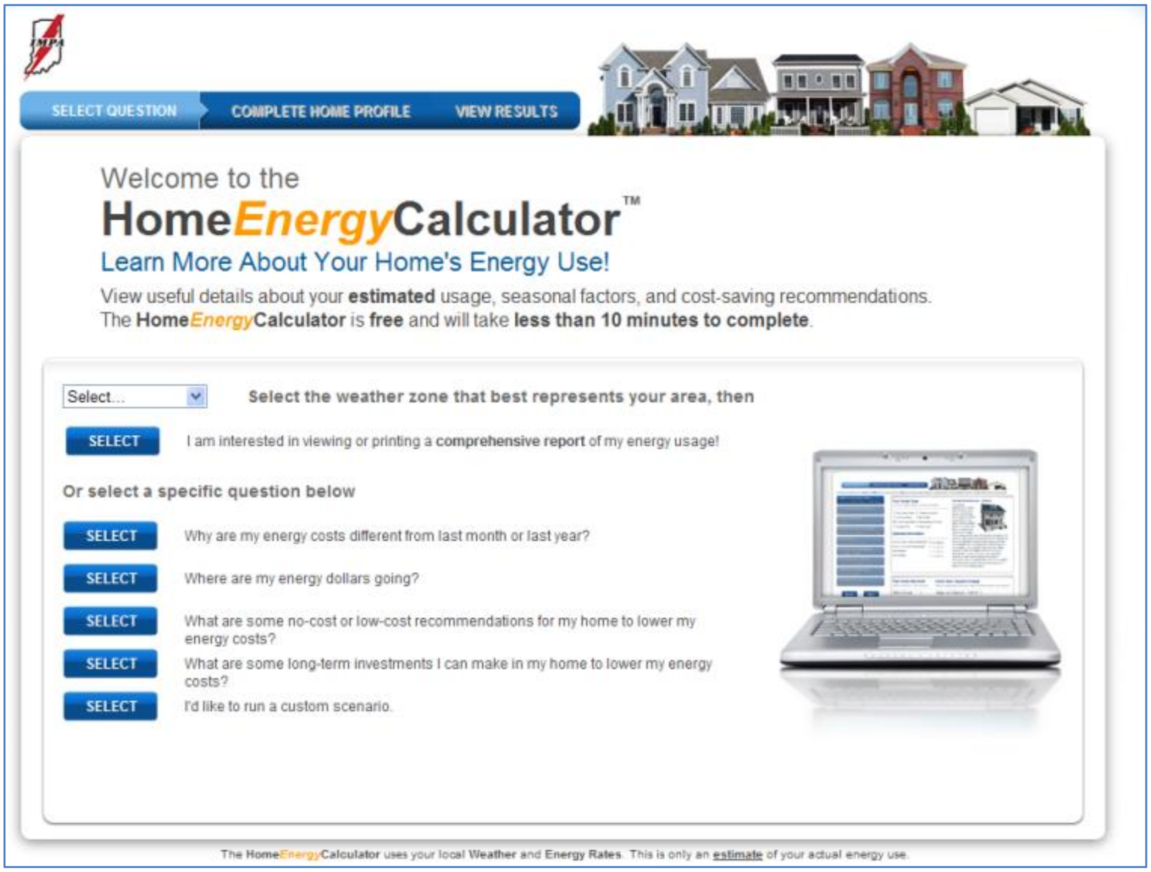
Member Programs

IMPA's members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy utilization. Most of these programs are rate or customer service related. Examples include coincident peak rates, off-peak rates, power factor improvement assistance, load signals to customer-owned peak reduction or energy management systems, AMI/AMR and streetlight replacement with more efficient lamps.

Home Energy Suite™

In March of 2009 IMPA contracted with APOGEE Interactive for the online Home Energy Suite™. This is an online application that allows customers to input information regarding their home and appliances and determine approximate consumption and costs of electricity. The application features many useful pages that allow consumers to see which appliances are costing them the most money, where they can save money, potential savings from higher efficiency appliances, etc. The site is hosted on IMPA's website, with most member communities offering links from their websites (some smaller towns do not have utility websites and high speed internet access is not available in all IMPA communities). The site is also advertised in IMPA newsletters.

Figure 4 IMPA Home Energy Calculator



Source: http://www.impa.com/homeenergysuite

Since 2009, IMPA's energy efficiency programs have continued to grow with a cumulative savings of 104,175 MWh at the end of 2014 and a coincident peak reduction of 11.332 MW.

Table 4 Energy Efficiency Results (2009-2014)

MWh – Annual	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Residential Rebate (IMPA)	214					24
Street Lights (IMPA)		6,100	2,573	3,017		
C&I Prescriptive (IMPA)			7,619			2,988
C&I Prescriptive (EI)				19,504	37,155	
Res Lighting (EI)				5,907	8,585	
Low Income (EI)				391	398	
Home Audit (EI)				1,752	5,179	
Schools (EI)				1,410	1,360	
Annual Total (MWh)	214	6,100	10,191	31,980	52,677	3,012
Cumulative Total (MWh)	214	6,314	16,505	48,485	101,163	104,175

MW (Non-Coincident)	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Annual Total (MW)	0.068	1.539	1.807	7.194	11.468	0.797
Cumulative Total (MW)	0.068	1.607	3.414	10.608	22.076	22.873

MW (Coincident)	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Annual Total (MW)	0.039	0.000	0.654	3.907	6.279	0.453
Cumulative Total (MW)	0.039	0.039	0.693	4.600	10.879	11.332

4.5 IMPA TRANSMISSION

A large portion of IMPA's load is connected to the Joint Transmission System (JTS) that is jointly owned by DEI, IMPA and WVPA. Pursuant to the terms of the "Transmission and Local Facilities Ownership, Operation and Maintenance Agreement" (the T&LF Agreement) and the "License Agreement," IMPA dedicated and licensed the use of its portion of the JTS to itself, DEI and WVPA. DEI and WVPA similarly dedicated and licensed the use of their facilities to IMPA. The T&LF Agreement provides mechanisms for the owners to maintain proportionate ownership shares and to share proportionately in the operating costs and revenues from the JTS.

IMPA owns, but does not operate transmission facilities. DEI is responsible for the operation and maintenance of the JTS. In addition, DEI performs all load and power flow studies for the JTS and recommends improvements or expansions to the JTS Planning Committee for its approval. DEI files the FERC Form 715 on behalf of the entire JTS. See Appendix H for a statement on Form 715.

IMPA is a member of MISO as a Transmission Owner (TO). DEI and WVPA are also TO members of MISO. The higher voltage facilities of the JTS are under the operational and planning jurisdiction of MISO. The initial purpose of MISO was to monitor and control the electric transmission system for its transmission owner members in a manner that provides all customers with open access to transmission without discrimination and ensures safe, reliable, and efficient operation for the benefit of all consumers. Although MISO has since expanded its mission to include the operation of various markets, it also continues to fulfill this initial purpose.

Approximately 67% of IMPA's load is connected to delivery points on MISO-controlled transmission lines of the JTS, NIPSCO and Vectren. The remaining portion of the members' load is connected to delivery points on the AEP and Duke-OH transmission systems, located in the PJM footprint. IMPA is a transmission dependent utility (TDU) for all load not connected to the JTS system, approximately 50%. IMPA purchases Network Integration Transmission Service (NITS) under the appropriate transmission owner's NITS tariff.

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5 LOAD FORECAST

As a basis for this integrated resource plan, IMPA developed a 20-year monthly projection of peak demands and annual energy requirements. This section describes the forecast methodology, forecast results, model performance, and alternate forecast methodologies.

5.1 LOAD FORECAST METHODOLOGY

IMPA uses IBM's Statistical Package and Service Solutions (SPSS) statistics predictive analytics software for generating its load forecasts using time series analysis. Causal time series models such as regression and Auto Regressive Integrated Moving Average (ARIMA) will incorporate data on influential factors to help predict future values of that data series. In such models, a relationship is modeled between a dependent variable, time, and a set of independent variables (other associated factors). The first task is to find the cause-and-effect relationship.

An ARIMA model can have any component, or combination of components, at both the non-seasonal and seasonal levels. The name autoregressive implies that the series values from the past are used to predict the current series values. While the autoregressive component of an ARIMA model uses lagged values of the series values as predictors, the moving average component of the model uses lagged values of the model error as predictors. The integration component of the model provides a means of accounting for trends within a time series model.

The SPSS forecasting software was used to create monthly forecasts for each IMPA load zone's energy requirements. The ARIMA method allows for the development of a mathematical equation that accounts for both a seasonal influence and an overall trend based on the data available.

5.2 LOAD DATA SOURCES

To create a consistent historical database for developing the statistical models, additional demand and energy data for Argos, Coatesville, Huntingburg, Jasper, Montezuma, New Ross, South Whitley, Straughn, Veedersburg, and Williamsport (part of DEI, NIPSCO, and SIGECO load zones) was included for the period prior to their respective IMPA memberships. Also, due to the Great Recession from late 2007 through 2009, there was a noticeable drop in all loads in Indiana, especially in the years 2009 and 2010. Thus, the models excluded the 24 months in '09 and '10 in order to better analyze the base trends and growth. In addition, since the historical energy requirements data reflect energy efficiency program reductions from 2011 through 2014, IMPA added the energy from these programs back into the historical energy allowing the statistical models to analyze the natural load growth. As a result, IMPA used 108 observations of monthly historical energy requirements in developing the AEP, DEI, and SIGECO forecast models, while the NIPSCO and Blanchester models, had 84 and 72 observations, respectively.

Monthly historical heating and cooling degree-days (HDD and CDD) with a base temperature of 65 were obtained for the period 1994 through 2014 from the National Oceanic and Atmospheric Association—NOAA (www.noaa.gov). Weather data was selected from four weather stations in Indiana and Ohio for their proximity to IMPA's 60 member communities; the Indianapolis weather station for the AEP and DEI load zones, South Bend for NIPSCO, Evansville for Vectren, and Cincinnati for Blanchester.

Economic variables used in the models include Indiana real personal income and the U.S. unemployment rate, from the Bureau of Economic Analysis (www.bea.gov) and Bureau of Labor Statistics (www.bls.gov), respectively. In addition to these variables, IMPA implemented the number of peak days and off-peak days per month as variables in the models to quantify monthly usage variability.

5.3 LOAD FORECAST MODEL DEVELOPMENT

Since 2011, IMPA has generated forecasts for each of IMPA's five load zones on the same basis as power is dispatched and reported to MISO and PJM. The load zones where IMPA has members include AEP, Duke Energy Indiana (DEI), Duke Energy Ohio Kentucky (DEO), NIPSCO (NIP), and SIGECO (SIG). The dependent variable in the energy model was the sum of each load zone monthly energy requirements (kWh). The independent variables were CDD, HDD, on/off-peak days and economic variables. Multiple models were created in SPSS and the best fit models were chosen after careful attention was given to the statistics and growth rates, making sure all were within an acceptable range and reflect the historical data. Developing energy forecast models for five zones allowed greater attention to statistics and model detail than could be done by forecasting the member cities individually.

Forecasts were obtained for each independent variable. Weather variables cannot be forecasted for more than a week or so with any level of accuracy, therefore, averages of the historical monthly data were used. The weather data was normalized for each month using the period 1994 through 2014, and this normalized weather was repeated annually from 2015 through 2035. The Unemployment Rate was projected using forecasted rates from the United States Congress Congressional Budget Office's (CBO) Budget and Economic Outlook: Fiscal Years 2015 to 2025 report (www.cbo.gov). For years 2026 through the 2035 the growth trend assumption for 2025 was continued. Economic variable personal income was projected using a general annual inflation rate of 2.5%, consistent with the inflation assumption used throughout IMPA's IRP.

5.4 SPSS MODEL SELECTION

The SPSS software produced model fit parameters, residual errors and variable coefficients. The R-square, t-Statistics and coefficients were then evaluated to determine whether to keep or eliminate a model. The statistical validity of each forecast model was evaluated focusing on the R-square and error residuals of the models, the sign of each coefficient and the significance of each t-Statistic of the variables. For example, the degree day weather variables should have a positive sign on the coefficient indicating that as the temperatures increase or decrease from the base temperature (65), the load increases. The personal income economic variable should have a positive sign as well, indicating as the economy grows, electricity use will increase. An exception here is the unemployment rate; the sign of the coefficient would be negative, because as the joblessness rises, spending/consumption/usage should inversely decrease.

The t-Statistics of all independent variables were significant, minimum 2.0, showing that the variable contributes significantly to the model against the null hypothesis. The R-square statistic measures how successful the fit of the model is in explaining the variation of the historical data—a 1.0 R-square would explain 100% of the variation. In selecting models, higher R-squares with higher t-statistics were used to determine the best models for the forecast.

5.5 LOAD FORECAST DEVELOPMENT

Energy Forecasts

Having input the monthly projections of the independent variables for 2015 to 2035, the SPSS software was used to compute the energy forecasts from the selected energy models. For quick visual analysis of the load curves and growth rates, the SPSS software also generated a graph of the fitted historical and forecast data. The SPSS software completed monthly energy projections from 2015 to 2035 and developed the monthly residual from the models. The SPSS forecasted data were then exported and transferred into Microsoft Excel for further analysis.

Demand Forecasts

IMPA gathers historical coincident and non-coincident (maximum) monthly peaks and energy requirements for each member. Using this information, various monthly relationships are determined:

A. Ratios of individual member energy requirements to load zone energy requirements
B. Load Factors of member energy requirements and member non-coincident (maximum) demand
C. Coincidence Factors of member coincident demand (coincident with load zone demand) to member non-coincident demand

Monthly historical average contributions of each member to the load zone energy requirements (A) are used to allocate the load zone energy forecasts back to individual members. Based on the historical monthly median non-coincident load factors (B), the monthly maximum loads are then calculated for each member. Finally, using the historical median monthly coincident factors (C), IMPA calculates each member's contribution to the load zone monthly coincident and billed demand forecasts. These demands are summarized to finalize the load zone demand forecasts. All the individual load zone forecasts are aggregated to produce the IMPA forecast.

Adjustments to Forecasts

No adjustments were made for potential gain or loss of large customers in member communities. In addition, while a few of the retail customers of IMPA's members have evaluated combined heat and power (CHP) generation over the past two years, no customers have opted to generate their own power on a larger scale as a result of economic analyses. Therefore IMPA did not adjust the forecast for CHP.

5.6 Base Load Forecast Results

The forecast of IMPA's expected peak demands and annual energy requirements is shown in the table below. The resulting long-term average growth rate is 0.4% for peak demand and 0.5% for energy.

Table 5 IMPA Expected Peak Demands and Annual Energy

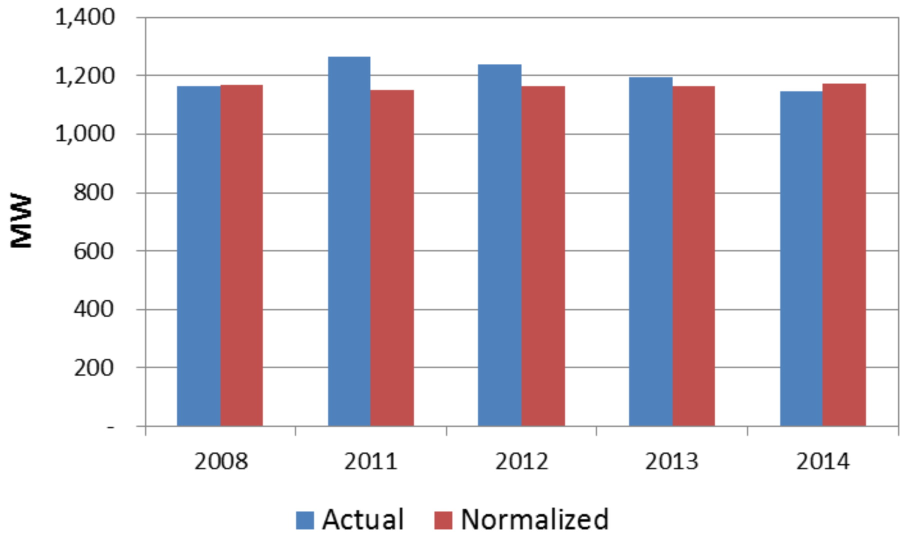
Year	Peak Demand (MW)	Energy Requirements (GWh)	Annual Load Factor (%)
2016	1,190	6,329	60.7%
2017	1,195	6,363	60.8%
2018	1,199	6,383	60.8%
2019	1,202	6,403	60.8%
2020	1,207	6,431	60.8%
2021	1,211	6,460	60.9%
2022	1,217	6,496	60.9%
2023	1,222	6,525	61.0%
2024	1,227	6,555	61.0%
2025	1,232	6,586	61.0%
2026	1,238	6,617	61.0%
2027	1,243	6,649	61.1%
2028	1,248	6,682	61.1%
2029	1,254	6,716	61.1%
2030	1,260	6,750	61.2%
2031	1,266	6,785	61.2%
2032	1,271	6,820	61.3%
2033	1,278	6,857	61.2%
2034	1,284	6,894	61.3%
2035	1,290	6,932	61.3%
CAGR %	0.41%	0.46%	

5.7 Weather Normalization

To evaluate load growth, it is important to quantify the percentage of the actual historical load which was a function of non-normal weather. This requirement is precisely why IMPA's forecasting models include weather variables. The models identify the portion of the actual load which has been influenced by weather.

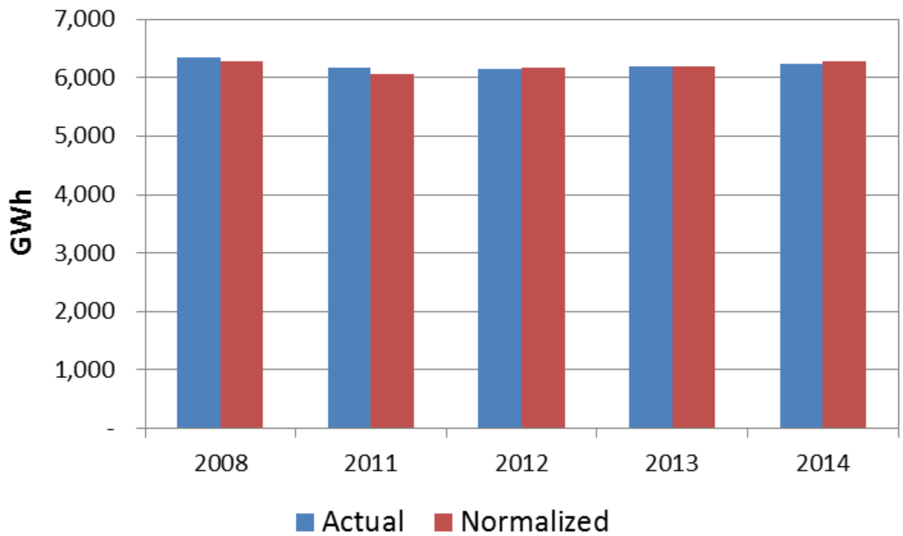
To weather normalize the historical data, IMPA first multiplies the coefficient(s) of the independent variables representing weather by the actual weather data. Then the same coefficients are multiplied by the normal weather data. The difference between the value derived using the actual weather and the normal value is used to adjust the actual loads to create the weather-normalized historical data.

Figure 5 Weather-Normalized Historic Peak Demand



Source: IMPA

Figure 6 Weather-Normalized Historic Energy



Source: IMPA

5.8 Load Forecast Model Performance

The following table compares the IMPA peak demand forecast used in the last five IRPs with actual results.

Table 6 Load Forecast Performance – Peak Demand

Year	Actual	Normalized	2013 IRP	2011 IRP	2009 IRP	2007 IRP	2005 IRP	Normalized Deviation From Most Recent IRP	Increase in IMPA Members*
2006	1,082	1,076					1,090	-1.3%	8
2007	1,161	1,143					1,121	2.0%	2
2008	1,125	1,103				1,265	1,140	-12.8%	1
2009	1,102	1,091				1,294	1,159	-15.7%	1
2010	1,163	1,149			1,134	1,308	1,177	1.3%	1
2011	1,226	1,184			1,155	1,322	1,196	2.5%	0
2012	1,215	1,164		1,168	1,172	1,336	1,215	-0.3%	4
2013	1,194	1,165		1,182	1,189	1,350	1,234	-1.4%	2
2014	1,147	1,172	1,223	1,196	1,206	1,364	1,253	-4.2%	0
CAGR %	0.65%	0.95%	--	0.79%	1.24%	1.08%	1.56%		

*The forecast in this table was developed prior to the years shown and therefore does not reflect the addition of new members. However, new member load is included in the actual and normalized data.

The following table compares the IMPA energy requirements forecast used in the last five IRPs with actual results.

Table 7 Load Forecast Performance – Energy Requirements

Year	Actual	Normalized	2013 IRP	2011 IRP	2009 IRP	2007 IRP	2005 IRP	Normalized Deviation From Most Recent IRP	Increase in IMPA Members*
2006	5,426,236	5,522,140					5,558,827	-0.7%	8
2007	5,957,491	5,843,662					5,728,295	2.0%	2
2008	6,193,164	6,097,488				6,292,085	5,829,988	-3.1%	1
2009	5,810,167	5,918,489				6,482,521	5,931,687	-8.7%	1
2010	6,112,550	5,947,164			6,065,212	6,551,133	6,033,392	-1.9%	1
2011	6,051,425	5,984,393			6,191,982	6,619,200	6,135,103	-3.4%	0
2012	6,097,288	6,042,314		6,160,345	6,312,798	6,686,761	6,236,820	-1.9%	4
2013	6,201,100	6,191,797		6,222,363	6,402,096	6,753,852	6,338,543	-0.5%	2
2014	6,225,553	6,270,787	6,274,153	6,273,437	6,511,904	6,820,504	6,440,272	-0.1%	0
CAGR %	1.54%	1.42%	--	-0.61%	1.43%	1.16%	1.65%		

*The forecast in this table was developed prior to the years shown and therefore does not reflect the addition of new members. However, new member load is included in the actual and normalized data.

5.9 ALTERNATE LOAD FORECAST METHODOLOGIES

Rate Classification/Sector Methodology

IMPA has not generated forecasts by rate classification or sector. Since IMPA does not sell directly to retail customers, it does not have direct access to customer billing units. To generate a customer sector forecast, IMPA would need to collect several years of annual historical billing summary data from each of its 60 members. In addition, the criteria determining member rate classes can change over time and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently. For example, two members may have a large power rate classification. Under this classification, one member's largest customer may be a 10 MW industry whereas the other may be a single 200 kW customer. For these reasons, sector forecasting would be very difficult for IMPA.

End-Use Methodology

Another forecast methodology is end-use. The data requirements for an end-use model are extensive. They include detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. IMPA's member communities are not uniform, they contain various ages of homes and businesses. The age of the residents and vintage of the houses can have a significant impact on the saturation of various appliances. To collect the proper saturation data at the member level, IMPA would need to collect a valid sample of each member's customers. A valid sample is approximately 300 customers whether the community is large or small. Additionally, since the response rate to surveys is typically 30% to 35%, IMPA would need to survey at least 1,000 customers in each community. This requirement makes end-use sampling unreasonable, considering that IMPA would need to sample 25% to 30% of all the customers its members serve. Most investor-owned utilities, while serving thousands more customers, would only need to sample about 1,000 customers to ensure a valid sample. Therefore, IMPA cannot realistically utilize this type of a forecast model.

6 RESOURCE OPTIONS

6.1 SUPPLY-SIDE OPTIONS

Potential supply-side options include upgrades to existing generating capacity, construction or acquisition of additional generating capacity, and entering into additional contracts for purchased power. New IMPA-owned capacity could include generating units constructed and owned by IMPA or participation in the ownership of either existing or new generating units with third parties. Purchased power could include purchases from other utilities, independent power producers or power marketers. While IMPA is well situated to construct, own and operate smaller generating facilities such as peaking plants, solar plants, landfill gas plants, and possibly even wind turbine plants, as a practical matter, IMPA would expect to participate with others in the development of any new large generation resources. Joint development of resources would enable IMPA to enjoy the economies of scale of a larger facility and at the same time adhere to the principle of diversification.

Additional Upgrades or Retirements of Existing Capacity

IMPA's existing generating capacity consists of its undivided ownership interests in Gibson 5, Trimble County 1 and 2, Prairie State 1 and 2, seven wholly-owned combustion turbines and member generating capacity that is dedicated to IMPA for its use. IMPA is not aware of any potential upgrades to the jointly-owned coal units that could increase their output capability. IMPA's generating member has reviewed its generating capacity to examine the feasibility of plant upgrades and improvements. All feasible upgrades have been implemented, and IMPA is not aware of any other potential upgrades to this capacity.

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. This is performed by allowing the expansion model to opt to close an existing resource and replace it with other alternatives. If a unit is retired in this manner, all future capital expenditures, O&M and fuel costs are removed, however, all remaining bond obligations associated with the facility remain. When a unit is retired it is assumed the decommissioning expense is equal to the salvage value.

For purposes of this IRP, IMPA assumes the diesel units at Rensselaer retire at the end of 2016. Actual retirement dates will vary as none of the units are specifically slated for retirement at this time. As such, the plans shown in this report could change depending on actual retirement dates or plant conversions.

New Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. For example, IMPA does not screen various brands and models of CTs against each other to determine the generic CT for use in the IRP expansion. CT pricing is sufficiently compressed in that one CT brand over another will not cause the expansion model to select a CT when a CT is not needed or vice versa. The selection of the actual brand and model to construct would be determined in the bid and project development process.

The traditional generating resources considered in this study include:

- Nuclear (100 MW from a 1100 MW unit)
- Coal-fired steam generation (100 MW from a 1300 MW unit)
    - with or without carbon capture and sequestration (CCS) depending on the scenario
- Integrated Gasification Combined Cycle (IGCC) (100 MW from a 620 MW unit)
- Advanced combined cycle (CC) units (100 MW from a 450 MW unit)
- Advanced gas-fired combustion turbines (CT) (185 MW)
- Aero-derivative CT (100 MW)
- Gas-fired high efficiency internal combustion (IC) units (10 MW units in multi-unit sets of 50 MW)

Capital costs, operating costs and operating characteristics for these sources were taken from *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, US Energy Information Administration, April, 2013 and *Annual Energy Outlook 2015*, US Energy Information Administration, April, 2015. See Appendix F for detailed expansion unit data.

During IMPA's consideration of supply-side resources, it assumes any new resource would comply with the applicable environmental requirements. Such requirements specify that the potential resource undergoes an environmental review prior to the beginning of construction and that the potential resource complies with any environmental constraints. If IMPA petitions the IURC for approval relating to new supply-side resource, IMPA would include information concerning these environmental matters, including the results of any due diligence investigations.

Power Purchases

Although IMPA has not identified any specific long-term firm purchased power options at this time, it will continue to consider such options as they may become available in the future.

Energy Markets

IMPA participates in both the MISO and PJM markets for balancing capacity and short-term purchases/sales. IMPA does not believe it is prudent to rely on these short term capacity and energy markets to meet its long-term capacity and energy requirements and allows the expansion model to add resources to meet its RTO resource obligations. However, in the expansion analysis, small amounts of annual market capacity purchases (100 MW MISO, 50 MW PJM) are allowable. This buffer also allows flexibility in the future regarding load uncertainty, energy efficiency, demand response and renewables development.

For purposes of this IRP, IMPA limits the installation of new resources to those needed to serve its own load. Although IMPA will sell short–term surplus capacity and energy through the organized markets, IMPA will not install generation for the purpose of speculative sales. The expansion model is set to limit the quantity of off system sales. This has the effect of limiting the selection of new resources to those required to meet IMPA's load since units won't be selected based on large off system revenues.

6.2 Renewable Options

In addition to the traditional resources discussed above, the expansion model was allowed to select from a variety of renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Wind
- PV Solar
- Bio Mass (25 MW)
- Landfill Gas (LFG) (2.5 MW units in sets of 10 MW)

Pricing for all of the renewable alternatives was based on IMPA's experience in constructing facilities, indicative market quotes from renewable energy providers or industry documentation of installed and operating costs.

See Appendix F for detailed expansion unit data.

IMPA is in the process of developing solar park projects. The current plan assumes 50 MW of solar park development over the next five (5) years in addition to the 13 MW already developed. Additional renewable energy additions were left up to the expansion model to determine.

6.3 Demand-Side Options

IMPA's goal is to provide low cost, reliable, and environmentally-responsible electric power to its members. IMPA accomplishes this by maintaining a diverse set of energy resource options with equal treatment between supply-side and demand-side resources (DSM). This is the essence of integrated resource planning. The DSM alternatives included in the expansion analysis are shown below.

- Energy Efficiency
- Demand Response

Pricing for the DSM alternatives was based on IMPA's past experience with DSM programs as well as industry research from the American Council for an Energy-Efficient Economy (ACEEE).

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7 ENVIRONMENTAL

7.1 COMPLIANCE WITH CURRENT RULES

The majority of IMPA's current resources are not substantially impacted by the EPA's rules slated to go into effect in the next few years. The following sections describe compliance actions IMPA expects to be taken at its generating facilities in connection with environmental rules.

General

Cross State Air Pollution Rule

On December 23, 2008, the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) remanded the Clean Air Interstate Rule (CAIR) to the EPA, but did not vacate the rule. This ruling left CAIR in place until the EPA issued a new rule consistent with the court's decision. The final replacement rule, the Cross-State Air Pollution Rule (CSAPR), was issued by EPA in July 2011. CSAPR was subsequently vacated by the D.C. Circuit in August 2012. The EPA then petitioned the D.C. Circuit for rehearing en banc, and this petition was denied in January 2013. The United States, through the Solicitor General, petitioned the U.S. Supreme Court in March 2013 to review the D.C. Circuit's decision on CSAPR. In June 2013 the U.S. Supreme Court agreed to hear the CSAPR case of the U.S. Government. On April 29, 2014, the United States Supreme Court issued an opinion upholding CSAPR, sending CSAPR back to the D.C. Circuit for review. On June 26, 2014, the EPA filed a motion requesting that the D.C. Circuit lift its stay on CSAPR and extend CSAPR's compliance deadlines. On October 23, 2014 the D.C. Circuit lifted its stay on CSAPR. On July 28, 2015, the D.C. Circuit decided certain outstanding legal issues related to CSAPR, including that the EPA must reconsider the 2014 SO_2 and ozone season NO_x emissions budgets for 13 upwind states, neither of which effect any IMPA generating unit. Despite this decision, CSAPR's compliance periods began on January 1, 2015. IMPA expects that the Agency will have to acquire a small percentage of its overall SO_2 and NO_x emission allowances needed for compliance, but that there will be no material impact from CSAPR on IMPA's generating facilities.

The Mercury and Air Toxics Standards

Following the vacating of the Clean Air Mercury Rule (CAMR), the EPA subsequently announced its decision to develop more encompassing hazardous air pollutant emissions standards for power plants under the Clean Air Act (Section 112, MACT standards) consistent with the D.C. Circuit's opinion vacating CAMR. EPA issued a proposed rule, Mercury and Air Toxics for Power Plants (MATS), in March 2011. The final rule became effective in April 2012 and was reconsidered and updated in April 2013 with revised emission limits for new or reconstructed units. Compliance is required for units greater than 25 MW by April 2015, or April 2016 if an extension is granted by the permitting authority for those units installing upgraded equipment for compliance. On June 29, 2015 the U.S. Supreme Court remanded the MATS rule to the D.C. Circuit Court because EPA did not properly consider costs as it wrote the rules. The D.C. Circuit must now decide whether to vacate the rule or remand it back to the EPA without vacatur.

Coal Combustion Residuals Rule

The utility industry is now likely faced with a more stringent regulatory scheme for managing CCRs due to the EPA's consideration of new regulations for CCRs. The EPA issued a proposed rule on June 21, 2010. Comments were taken through November, 19, 2010 on two alternative proposals. Environmental groups filed suit against the EPA in April 2012 to force the EPA to take action on the proposed rule. On October 19, 2015, the CCRs rule to regulate the disposal or coal ash as nonhazardous waste from coal-fired power plants under subtitle D of the Resource Conservation and Recovery Act (RCRA) came into effect. The rule establishes nationally applicable minimum criteria for the safe disposal of coal combustion residuals in CCR landfills, CCR surface impoundments and all lateral expansions of CCR units. It applies to new and existing facilities. The CCR rule was promulgated as a self-implementing rule (as provided under RCRA Subtitle D) meaning that it does not require regulated facilities to obtain permits, does not require states to adopt and implement new rules and cannot be enforced by EPA. Instead, the rule allows a state or citizen group to bring a RCRA suit against any facility alleged to be in non-compliance with the rule's requirements.

CO_2 Emissions from Existing Power Plants

On August 3, 2015, the EPA released its final rule for regulating CO_2 from existing EGUs under section 111(d) of the Clean Air Act. This rule, commonly known as the Clean Power Plan, seeks to reduce CO_2 emissions from EGUs by 32 percent below 2005 levels by 2030. In order to comply with the rule, states must submit a state implementation plan (SIP) or seek a two-year extension by September 6, 2016. If a state chooses not to implement a state plan by September 8, 2018, then the EPA will implement a federal implementation plan (FIP) on the state. A state has the option to either pursue a rate-based plan, which would require the power fleet to adhere to an average amount of carbon per unit of power produced or a mass-based plan, which would cap the total tons of carbon the power sector could emit each year. If a FIP is placed on a state, it is not yet known whether the plan would take a rate-based or mass-based approach. The rule requires states' existing EGUs to meet a CO_2 emissions rate by 2030, and an interim average emission rate between 2022 and 2029. These rates were calculated using each state's 2012 adjusted baseline emissions rate. For Indiana, the required rate reduction is 38.5%. In the rule, EPA set forth a best system of emissions reduction ("BSER") for which the states can achieve these goals. The BSER includes three "building blocks" of which states can choose to use some or all in order to reach the state emission reduction goal. The "building blocks" include (1) heat rate improvements at the EGU; (2) dispatching natural gas combined cycle units with higher capacity levels than coal generating capacity and (3) increased use of renewable and non-emitting generation. Governmental, environmental and utility stakeholders, including IMPA, are working together to digest the rule, its implications and the best paths forward.

Effluent Limitation Guidelines

On June 7, 2013, EPA proposed a rule to amend Effluent Limitation Guidelines (ELGs) (40 CFR Part 423), which would affect steam generating units that discharge to surface waters. On September 30, 2015, the EPA finalized its ELG as required by its consent decree with the Defenders of Wildlife and the Sierra Club, entered into on March 18, 2012. The ELG rule will have minimal to no effect on Gibson 5 and Prairie State as they have no discharges. While Trimble County does not directly discharge process water, it is planning and budgeting for an appropriate system to put into place to achieve compliance in the rule's compliance period of 2018-2023.

Final Ozone National Ambient Air Quality Standards

Under the Clean Air Act, the EPA is required to review and, if appropriate, revise the air quality criteria for primary (health-based) and secondary (welfare-based) national ambient air quality standards (NAAQS) every five years. On March 23, 2008, EPA published a final rule to revise the primary and secondary NAAQS for ozone. EPA revised the level of the eight-hour ozone standard to 75 parts per billion (ppb). With regard to the secondary ozone standard, the EPA made it identical in all respects to the primary ozone standard, as revised. The D.C. Circuit upheld the primary standard, but remanded the secondary standard to the EPA.

EPA initiated the current review in October 2008 and proposed a draft rule in December 2014, lowering the standard to between 65 and 70 ppb. On October 1, 2015, EPA revised its NAAQS for ground-level ozone to 70 ppb. Under this rule, states will be required to develop and put in place pollution control plans for counties found to be in “non-attainment” with the limit. If the rule causes counties in which IMPA’s generating units are located to be designated as non-attainment, then the state will have to develop a compliance plan.

Waters of the United States (WOTUS)
The Army Corps of Engineers and EPA’s issued the final WOTUS rule on May 27, 2015, defining which streams, wetlands and other bodies of water are protected by the Clean Water Act (CWA). The rule went into effect on August 28, 2015, but on October 9, 2015 the U.S. Court of Appeals for the Sixth Circuit issued an ordering staying the rule nationwide.

The rule requires that discharges into WOTUS require CWA permits, WOTUS must meet water quality standards and citizens may sue to enforce the CWA. Included in the definition of WOTUS are now tributaries, adjacent waters, enumerated regional features with a significant nexus and waters in the 100-year floodplain or within 4,000 feet of a WOTUS with a significant nexus. Since all of IMPA’s units are equipped with cooling towers and lakes, the units do not directly discharge into jurisdictional waters. Therefore, IMPA is not aware of any effects this rule has on its units, but will continue monitoring the rule for future effects. The State of Indiana has joined a lawsuit, filed on June 30, 2015, alongside eight other states against the EPA to challenge the rule as unconstitutional.

Gibson #5
Gibson #5 currently complies with the SO_2, NO_x, particulate matter and opacity requirements of the Clean Air Act and Phase II of the Acid Rain Program. Gibson 5 also complies with Cross State Air Pollution Rule NO_x and SO_2 regulations. IMPA’s share of the SO_2 and NO_x emissions allowances allocated by the EPA and the Indiana Department of Environmental Management (IDEM) will satisfy most of IMPA’s requirements for such allowances.

Gibson 5 complies with the annual and seasonal requirements of the NO_x rule by operating its SCR system on an annual basis. Compliance with the CSAPR SO_2 rule at Gibson 5 was aided by a significant investment to upgrade the unit’s flue gas desulfurization system (FGD). This upgrade was done during an extended maintenance outage in the spring of 2008 with final modifications completed in the fall of 2009. Gibson 5 will likely need to purchase a small number of allowances for SO_2 and NO_x allowances in future compliance periods.

Gibson filed for, and received, a MATS extension from the IDEM. Final plans for MATS compliance include upgrading the electrostatic precipitator and adding calcium bromide injection. These upgrades will be in place prior to April 2016.

Non-hazardous solid waste from this bituminous coal fired unit consists of the following Coal Combustion Residuals (CCR): fly ash, bottom ash, and fixated sludge from the SO_2 scrubber. The solid waste is disposed of in a mono-purpose solid waste disposal facility on the site or beneficially reused in the close out of the surface impoundments at the site. DEI also actively pursues other alternative reuse of CCRs.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc. Gibson Station normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at Gibson Station are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

Trimble County 1

Trimble County 1 currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act.

Trimble County 1 complies with the CSAPR NO_x rules by operating the SCRs on an annual basis. IMPA expects its share of allowances to satisfy the most of the NO_x emissions at Trimble County.

Compliance with the CSAPR SO_2 rule is accomplished through the increased efficiency achieved through the significant investment made to upgrade the Trimble County 1 FGD system in the fall of 2005. IMPA expects its share of allowances to satisfy the CSAPR SO_2 emissions of Trimble County 1.

Solid waste from the bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LGE is currently developing a solid waste disposal facility for dry disposal of future CCR adjacent to the station. Additionally, LG&E actively pursues alternative reuse of CCRs.

Trimble County 1 is affected by the MATS rule, and has received a one year extension from the Kentucky Department of Air Quality. A pulse jet fabric filter and new induced draft fans are being installed to comply with the MATS Rule. The new equipment will be put online in late 2015.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Trimble County 2

As with Trimble County 1, compliance with CSAPR is required. Trimble County 2 will comply in the same fashion as Trimble County 1. Its allocation of NO_x and SO_2 allowances are adequate to cover its emissions.

Trimble County 2 is subject to the MATS rule and is fully equipped for compliance.

Solid waste from the bituminous and sub-bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LG&E is currently developing a solid waste disposal facility for dry disposal of future CCR adjacent to the station. Additionally, LG&E actively pursues alternative reuse of CCRs.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Prairie State Project

Prairie State Units 1 and 2 are subject to CSAPR. The Prairie State units receive CSAPR NO_x and SO_2 allowances from Illinois' new unit set aside which meet most of its emission requirements. Any remaining allowances that are needed for compliance will be purchased along with all the required SO_2 allowances required for compliance with the Title IV Acid Rain program.

The Prairie State units are subject to the MATS rule and are fully equipped for compliance.

Solid waste from these mine-mouth bituminous coal fired units consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid, dry waste is disposed at the near-field landfill. The breaker waste from the mine is disposed at the near-filed or the Jordan Grove facility via truck transport. Jordan Grove is a 1,100 acre site located near Marissa, IL. Jordan Grove was previously operated as a surface coal mine. The material is disposed under an Illinois Department of Natural Resources mining permit and an NPDES permit. PSGC actively pursues alternative reuses of CCRs.

Hazardous waste generation at Prairie State is similar to Gibson Unit 5 and Trimble County. All hazardous wastes generated by Prairie State are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

White Water Valley Station (WWVS)

WWVS currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act. WWVS complies with the CSAPR NO_x rules using low NOx burners and overfire air. IMPA expects its share of allowances to satisfy the NO_x and SO_2 emissions at WWVS. Solid waste from the bituminous coal consumed in the unit consists of the following CCRs: fly ash and bottom ash. The solid waste is disposed of in a private offsite facility, the mine from one of the fuel suppliers, and in certain instances, a surface impoundment on the site. IMPA is currently developing plans to discontinue use of the surface impoundment in its compliance plan for the CCR Rule.

WWVS is affected by the MATS rule, and has received a one year extension from the IDEM. A pulse jet fabric filter was installed in the 2010 time period and new sorbent and powder activated carbon injection systems are being installed to comply with the MATS Rule. The new equipment will be put online in late 2015.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc.

WWVS normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at WWVS are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

IMPA Combustion Turbines

All of IMPA's Combustion Turbine stations comply with the existing requirements of the Clean Air Act. This compliance is achieved through Title V Operating Permit restrictions on fuel consumption and the use of lean pre-mix fuel/air injectors or water injection for NO_x control. The stations meet CAIR NO_x emission allowance requirements with allocated and purchased allowances. The stations comply with their respective Acid Rain Permits using the Excepted Methodologies in 40 CFR 75. SO_2 allowances are either purchased or transferred from other IMPA-owned source allocations.

The units also must comply with CSAPR. CSAPR allowances required in excess of the allocation amount will be purchased.

The Anderson and Richmond turbines can operate on pipeline natural gas or No. 2 low sulfur fuel oil. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Each plant has chemical storage for use in its demineralized water treatment plant. At times hazardous waste may need to be disposed of when the chemical tanks are cleaned. A licensed contractor is hired to do this cleaning, remove the waste, and properly dispose of the waste. Infrequently, oily waste may be removed from collecting tanks located at the site. This waste is also disposed of using properly licensed vendors. Other waste disposal is similar to household waste and is removed by a licensed refuse removal company.

The Georgetown units are single fuel units that operate solely on pipeline natural gas. There is no chemical storage on site and the plant's parts washer contains non-hazardous solvent. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Most waste disposal consists of waste similar to household waste and is removed by a licensed refuse removal company. There may be, at infrequent times, oily waste removed from onsite collecting tanks. This waste is also disposed of using properly licensed vendors.

7.2 Compliance with Future Rules

IMPA makes no assumptions as to future environmental rules or laws. For purposes of this analysis, it is assumed that all future resource options comply with the existing environmental rules in place at the time of installation.

7.3 Renewable Energy and Net Metering

IMPA current renewable energy sources consist of a 50 MW wind contract and 10 MW of solar facilities.

Since 2009, the Crystal Lake wind contract has supplied approximately 2.5% of IMPA's annual energy requirements.

IMPA solar parks are currently operating in the following communities:

- Frankton (1 MW)
- Rensselaer (1 MW)
- Richmond (1 MW)
- Tell City (1 MW)
- Peru (3 MW)
- Crawfordsville (3 MW)

In addition to the solar facilities listed above, IMPA is currently developing solar parks in the communities of Pendleton (2 MW), Argos (.7 MW) and Bainbridge (.3 MW) that will be operational before the end of 2015.

As stated previously, IMPA's net metering program is implemented at the member level at the member's discretion. At this time, IMPA members have approximately 15 participants in their net metering programs.

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8 TRANSMISSION AND DISTRIBUTION

8.1 FUTURE TRANSMISSION ASSUMPTIONS

As noted previously, IMPA is a member of MISO as a TO within the DEI area and is a TDU within the NIPSCO and Vectren areas of MISO. IMPA is also a TDU receiving transmission service from PJM for its loads in that footprint.

MISO performs all of the transmission system planning for the facilities under its operational control, which includes most of the JTS. In the DEI load zone, DEI performs any additional transmission system planning functions on behalf of the three owners of the JTS (see Appendix H for statement regarding Form 715). IMPA participates in the joint owners' Planning Committee, which reviews major system expansions planned by DEI. IMPA assists its members where needed in determining when new or upgraded delivery points are required and coordinates any studies, analyses or upgrades with other utilities.

Rates for MISO and PJM area-specific NITS and ancillary services were escalated to reflect increased cost for transmission service over the study period. Additionally, charges for the MISO's Network Upgrade Charge (Schedule 26) and Multi Value Project Charge (MVP) adder (Schedule 26a) were increased based on projections provided by MISO. This reflects the increases in these charges due to the construction of the transmission and MVP projects over the next decade.

Each year, IMPA pays a significant amount of money for RTO congestion and losses. IMPA has investigated with consultants and the RTOs methods by which IMPA could invest in transmission improvements as another way to help mitigate congestion risk at some of its resource Commercial Pricing Nodes (CPNODES). At this time, no economic upgrades have been found, but IMPA continues to research viable projects.

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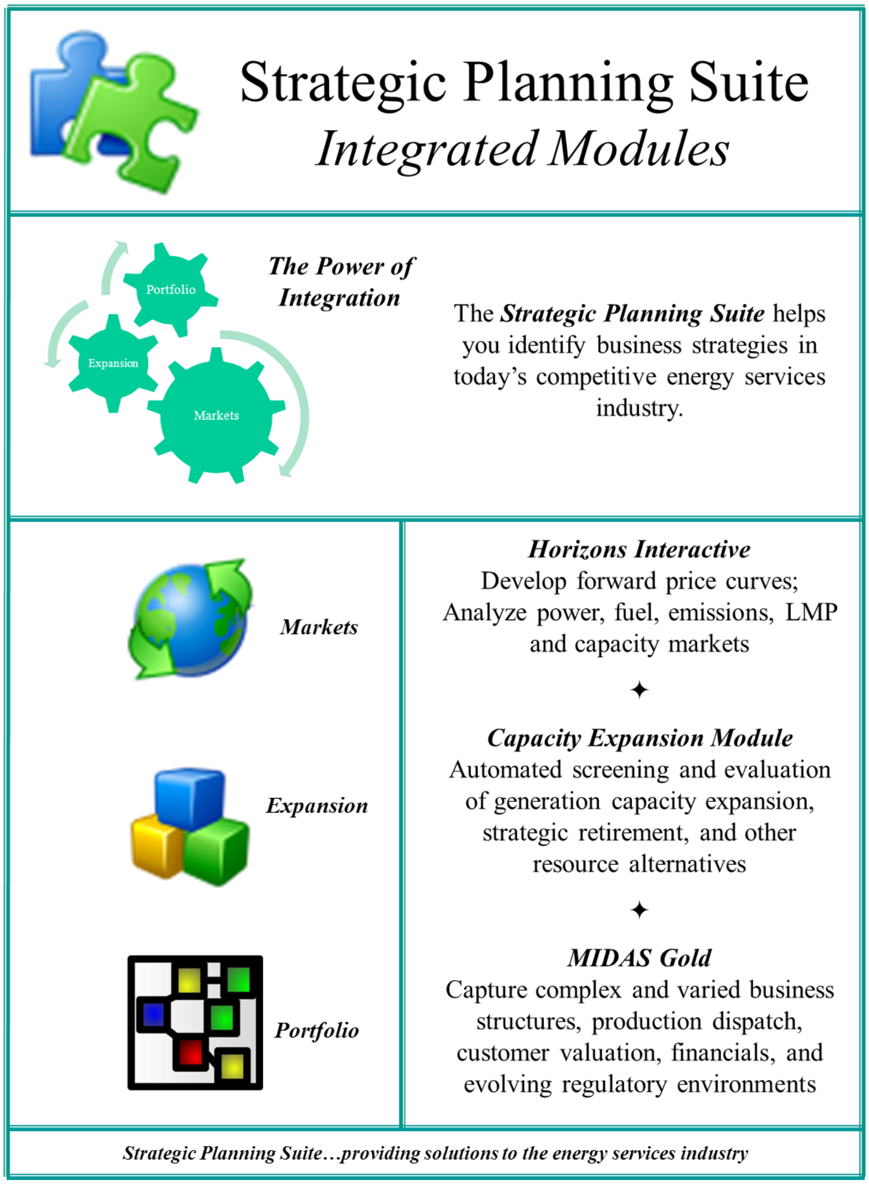
9 SOFTWARE OVERVIEW / DATA SOURCES

IMPA utilizes the Ventyx Strategic Planning Suite ("Strategic Planning") and Risk Analyst tools to perform its resource planning studies.

9.1 STRATEGIC PLANNING SUITE

Strategic Planning consists of three integrated modules that pass inputs and results between the modules. Each module is designed to address specific business problems associated with the power industry.

Figure 7 Strategic Planning Suite Cut Sheet



Source: Ventyx

INTEGRATED RESOURCE PLAN 2015

Horizons Interactive

The Horizons Interactive market module develops forward price curves and analyzes power, fuel, emissions, energy and capacity markets. The model is also able to calculate a shadow price of CO_2. The simulated forward market trajectories are used by the next set of modules in the Suite.

Capacity Expansion Module

The Capacity Expansion module is an optimization screening tool that completely enumerates the possible combinations of new resource additions, DSM programs, and strategic retirements. The screened resource plans are then evaluated in greater detail in the MIDAS Gold module.

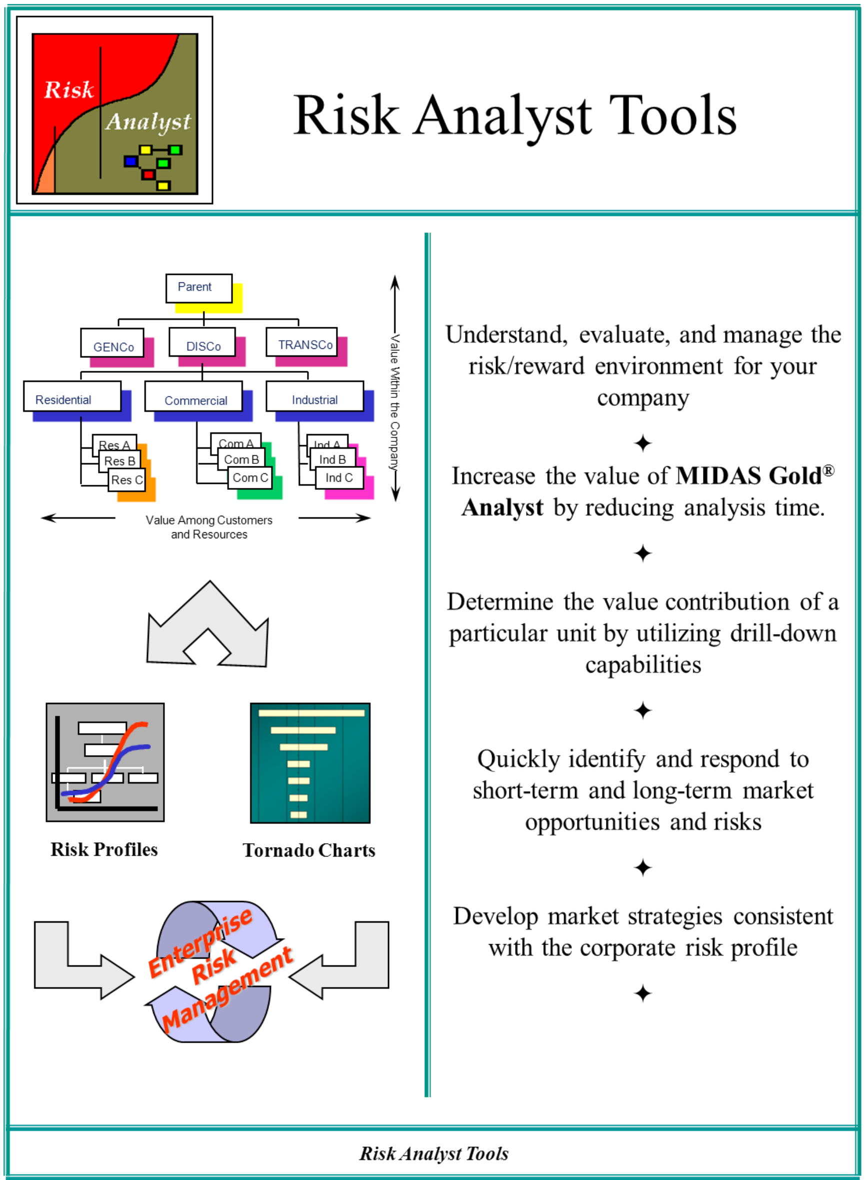
MIDAS Gold

Once the forward curves and optimized resource plans are developed, the MIDAS Gold module is used to create IMPA specific business structures complete with pro forma financials and rate making. The module mimics utility operation by combining unit commitment and dispatch with market purchases and sales and IMPA member revenue requirements/rate making; providing a complete analysis of each resource plan and scenario.

9.2 RISK ANALYST TOOLS

To assess the risk of the various plans, IMPA utilizes a variety of analytical tools and techniques. Among these are decision trees, risk profiles, tornado charts, and trade-off diagrams. When selecting a preferred plan, strong consideration is given for the robustness of the plan in addition to the relative cost and rate impact of the plan.

Figure 8 Risk Analyst Tools Cut Sheet



Source: Ventyx

9.3 External Data Sources

IMPA's database uses a mix of publicly available forecasted information and IMPA proprietary information from a variety of sources.

Table 8 External Data Sources

Source Title	Publishing Address
Annual Energy Outlook 2014 & 2015	U.S. Energy Information Administration Office of Communications, EI-40 Forrestal Building, Room 1E-210 1000 Independence Avenue, S.W. Washington, DC 20585
Velocity Suite Database	Ventyx 1495 Canyon Blvd, Suite 100 Boulder, CO 80302
SNL Database	SNL Financial LC PO Box 2124 Charlottesville, Virginia 22902
Planning Year 2015-2016 LOLE Study *Multi Value Project Portfolio*	Midcontinent ISO (MISO) 701 City Center Drive Carmel, IN 46032
The Evolution of Demand Response in the PJM Wholesale Market	PJM 2750 Monroe Boulevard Audubon, PA 19403
PJM's Reliability Pricing Model	The Brattle Group 1850 M Street NW, Suite 1200 Washington, DC 20036
2014 Long-Term Reliability Assessment	North America Electric Reliability Corporation (NERC) 3353 Peachtree Road NE, Suite 600 North Tower Atlanta, GA 30326
JD Energy's Forecasting Services	JD Energy PO Box 1935 120 Fairview Avenue Frederick, MD 21702-0935
Eastern Wind Integration and Transmission Study – February 2011 *PV Watts Calculator*	National Renewable Energy Laboratory 15013 Denver West Parkway Golden, CO 80401
Wind Vision: A New Era for Wind Power in the United States	U.S. Department of Energy 1000 Independence Ave., SW Washington, DC 20585
U.S. EPA Clean Power Plan for Existing Power Plants	U.S. Environmental Protection Agency 1200 Pennsylvania Avenue, N.W. Washington, DC 20460
GenHub Database	PennWell Corporation 1455 West Loop, Suite 400 Houston, TX 77027

10 SCENARIO DEVELOPMENT

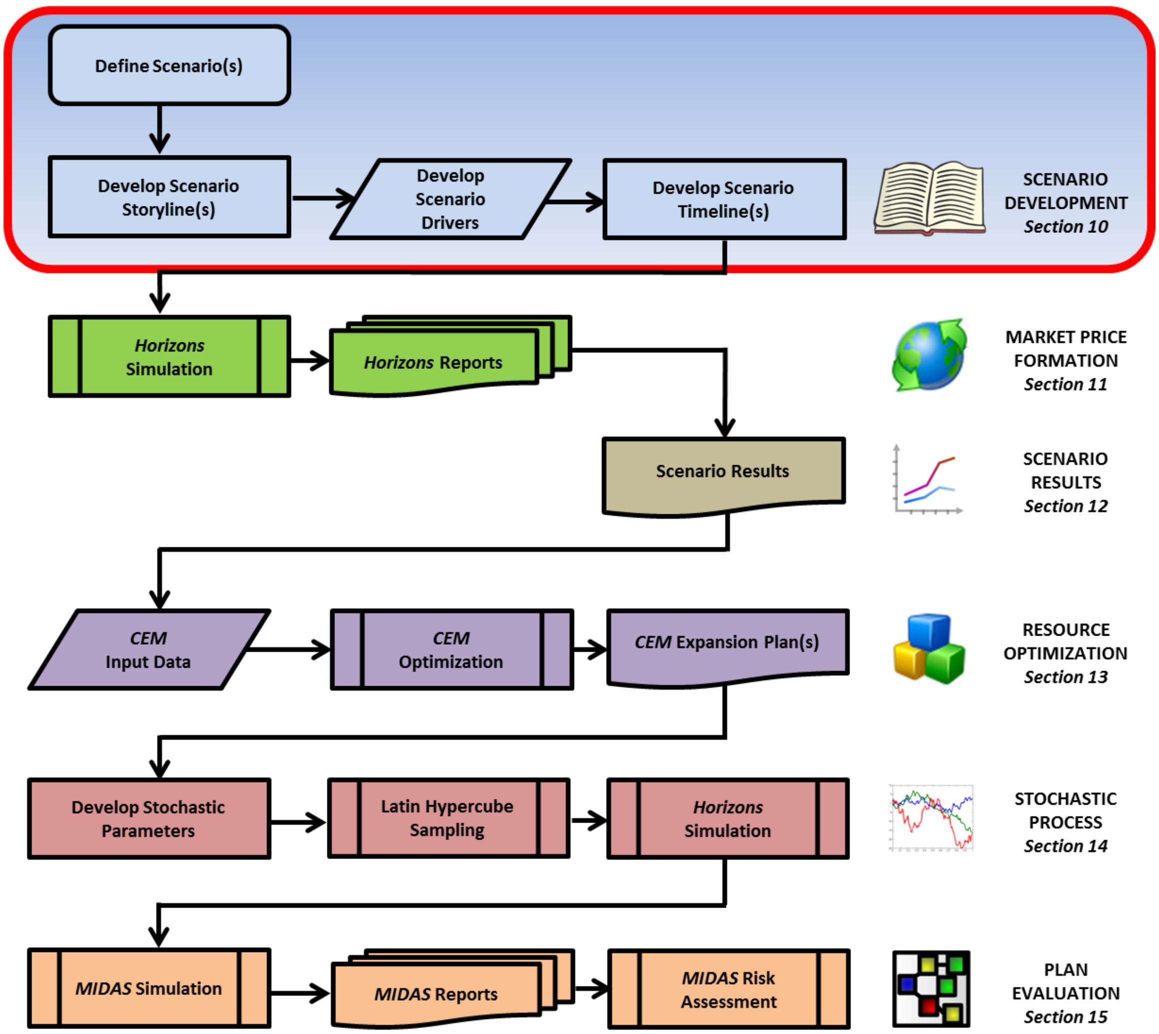
IMPA creates scenarios as a structured way to think about the future as scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. IMPA stakeholders develop stories about how the future might unfold by iteratively building plausible alternate views of the future given different economic, regulatory, and technological driving forces.

10.1 IRP Scenario Process

The process acknowledges that both today and tomorrow's business environments are increasingly complex and unpredictable. A key aspect of scenario planning for an electric utility is to transform the scenario narrative into electricity market characteristics that can be incorporated into the IRP process. This is not an easy task as it involves detailed modeling of electricity markets under the scenario's conditions—*essentially a NERC-Wide IRP for each scenario*.

Shown below is a flowchart which embodies the IRP process. The goal of defining and developing scenarios is the creation of alternate futures that result in different resource mixes. Ideally the scenarios serve as "book-ends" that examine a variety of high consequence outcomes.

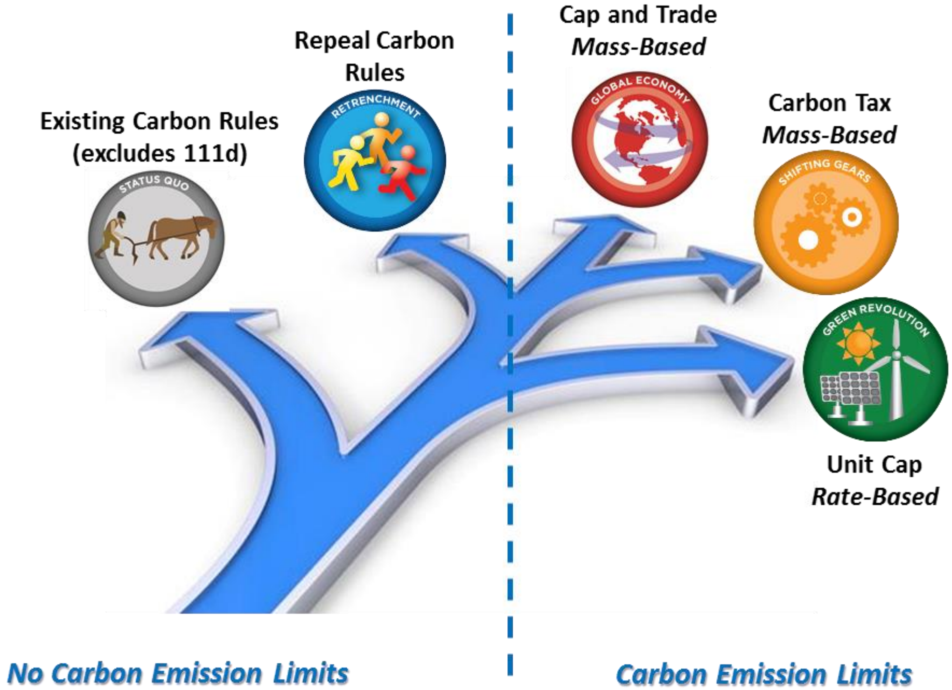
Figure 9 IRP Flowchart – Scenario Development



10.2 Scenario Themes

For the 2015 IRP, IMPA stakeholders identified five distinct themes which are expected to have the greatest impact on the future energy business environment over the next 20 years. IMPA looks for signposts that signal the scenario may occur, providing an early warning system of possible events to follow. The more credible signposts identified for any given scenario, the greater the likelihood that the scenario and its associated strategic implications will be relevant. While possible carbon regulations are a major factor of each theme - demand, fuel prices, technology, resources, reserve margins, etc. all play a role in the development of the scenario.

Figure 10 Scenario Roadmap



STATUS QUO

- Base Case
- Existing policies and technologies
- EPA 111(b) only

RETRENCHMENT

- Reliability/competitive concerns
- Traditional generating resources
- Repeal of EPA carbon rules

GLOBAL ECONOMY

- Increased free trade
- World economy booms
- Carbon cap and trade

SHIFTING GEARS

- Carbon compromise
- Investment in Coal CCS
- Carbon tax

GREEN REVOLUTION

- Strict environmental policies
- Load destruction
- Carbon rate cap by unit

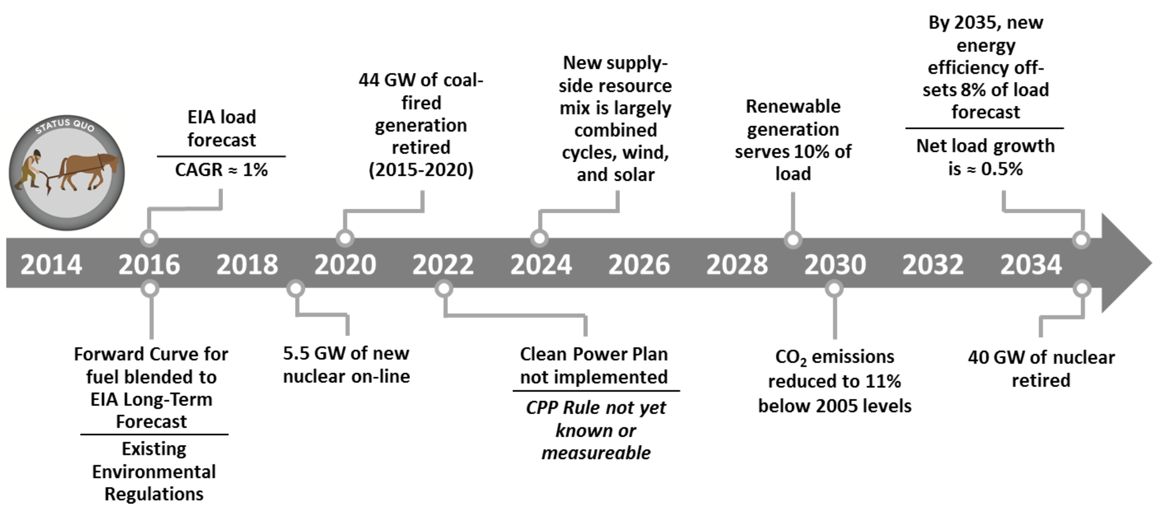
10.2.1 Status Quo Storyline/Timeline

The Status Quo scenario or Base Case includes only known events and expected trends (e.g., forecasts of fuel prices, economic forecasts, estimated future capital costs, expected load forecast, etc.). This scenario provides a 20 year projection without any unduly speculative and significant changes to resources or laws / policies affecting resources that aren't known and measureable.

During the preparation of this IRP, the Obama administration released the final version of the CPP (August 3, 2015). At this point in time, Indiana's compliance with the plan is neither known nor measureable. On June 24th, 2015 Indiana Governor Mike Pence sent a letter to President Obama informing him that unless the *proposed* federal EPA's CPP is demonstrably and significantly improved before being finalized, Indiana will not comply. Given the *final* rule puts Indiana in a far worse position than the proposed rule,[1] it is uncertain Indiana will voluntarily comply with the rule as written. As the opposition to the CPP is far reaching and will likely end-up in the U.S. Supreme Court, the implementation of the CPP is considered speculative so it is excluded from the Status Quo scenario. However, three additional scenarios (Global Economy, Shifting Gears, and Green Revolution) were developed to address the impact of the carbon emission limits set forth in the CPP rule.

To forecast unit retirements, Status Quo considers announced retirements as known and measureable. The impact of CSPAR and MATS compliance is significant as 44 GW of coal-fired generation have been publically announced for retirement between 2015 and 2020. By the end of the study, 64 GW of coal and 40 GW of nuclear generation are retired. It is assumed that renewable energy does not receive production tax credits (PTCs) or investment tax credits (ITCs) as there is no current legislation supporting these credits past their current expiration date. Energy efficiency is added economically in the states with an energy efficiency resource standard (EERS).

Figure 11 Status Quo Timeline

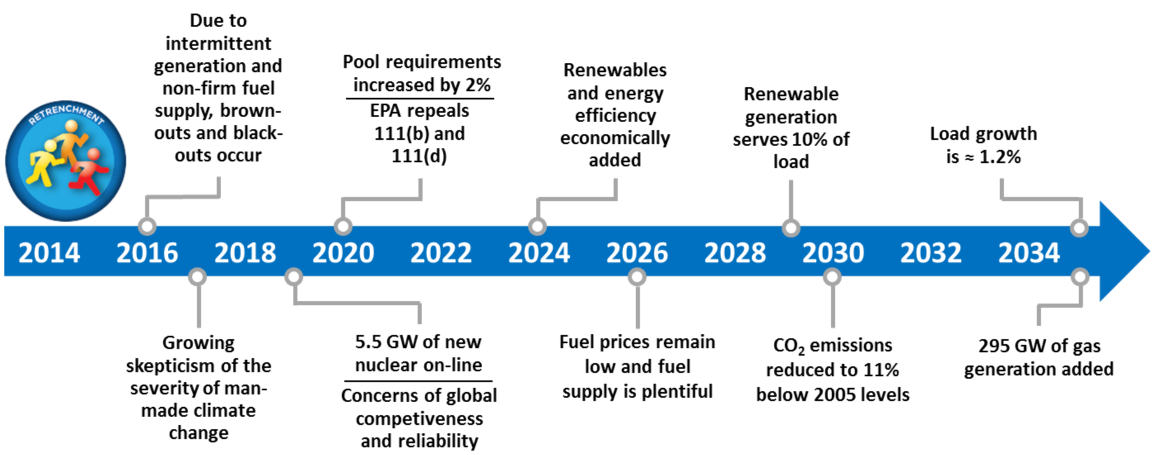


[1] From the proposed rule (June 2014) to the final rule (August 2015), the U.S. EPA completely overhauled its calculation of state emission goals, increasing the required reductions in the states where IMPA owns coal-fired generation (Indiana, Illinois and Kentucky) by 18%, 11%, and 22%, respectively.

10.2.2 Retrenchment Storyline/Timeline

The Retrenchment scenario is driven by system reliability and global competitiveness concerns. In response to brown-outs and black-outs, the reliability councils add capacity performance measures to ensure a robust electric grid. Intermittent generation (wind and solar) and energy efficiency are not eligible for capacity credit. EPA's sections 111(b) and 111(d) are repealed, permitting unencumbered construction and dispatch of fossil fuel units ensuring a reliable electricity supply. Reliability councils increase pool requirements by 2% to provide additional reserves. Natural gas supply is higher due to increased pipeline capacity.

Figure 12 Retrenchment Timeline



Retrenchment Signposts

IMPA stakeholders identified a number of signals that indicate the Retrenchment scenario is a plausible future. The polar vortex of 2014 illustrated the importance of coal generation as a reliable resource[2] in times of system emergency. Electricity is the lifeblood of modern society and any disruption has severe consequences to the U.S. economy and the health of its citizens. In the five year period from 2012 through 2016, 60 GW of coal either has been or will be retired placing the grid in a precarious situation when the next extreme weather event occurs. Thus, there is a reliability concern that the EPA's CPP, which intensifies coal retirements, will add to the grid's vulnerability. In times when the nation is very concerned about cyber-attacks, a tight reserve margin combined with an electricity grid fed by more and more intermittent resources adds to the brown-out and black-out susceptibility.

Further, there is fierce legal opposition[3] to the EPA's CPP and studies[4] have cited the economic pain stemming from the EPA's regulation would spread throughout the country. Especially hard hit would be low-income and fixed-income families as low-income families spend a far greater percentage of every dollar on energy costs. America's manufacturing base would be hit particularly hard by higher energy prices resulting in higher unemployment as U.S. businesses lose market share to global competition.

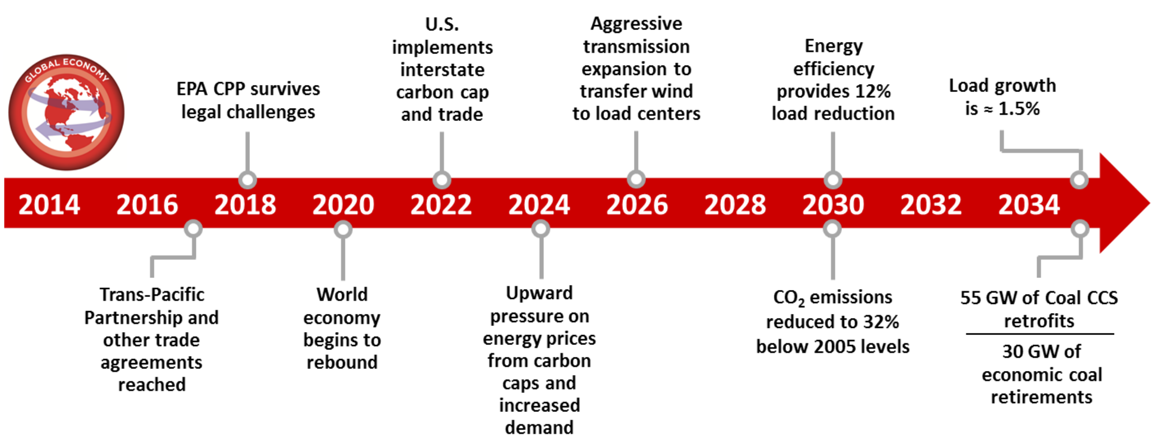
[2] *NERC Polar Vortex Review*, September 2014
[3] *15 states launch legal battle against EPA's Clean Power Plan*, Utility Dive, Davide Savenije, August 17, 2015
[4] *All Economic Pain, No Environmental Gain*, The Heritage Foundation, Nicolas Loris, June 5, 2014

10.2.3 Global Economy Storyline/Timeline

In Global Economy, the world powers increasingly participate in a free trade economy. A world economy requires the participants to operate under similar environmental rules and work conditions. In general, it is assumed this will benefit the U.S. as global competitors such as China, Mexico, and India will see increased costs to participate on a more level playing field. As manufacturing returns to the U.S. and the economy expands, higher energy needs place upward pressure on commodity prices.

To meet the EPA's CPP requirement of a 32% reduction in carbon emissions from the 2005 level by 2030, the U.S. implements an interstate CO_2 cap-and-trade program for existing and new resources. Beginning in 2022, each existing steam-coal, steam-oil, and combined cycle unit is allocated allowances based on a proportionate share of its state's annual cap using the unit's 3-year average CO_2 emissions (2010-2012). Under the assumptions in this scenario, the aforementioned existing generating units plus new units would participate in the trading program.

Figure 13 Global Economy Timeline



<u>Global Economy Signposts</u>

IMPA stakeholders identified a number of signals that indicate the Global Economy scenario is a plausible future. In his second term, President Obama has placed an emphasis on negotiating free and fair trade agreements[5] that level the global playing field. On this issue, the administration has found common ground with the Republican-controlled Congress. As technology has advanced in transportation and communication, there has been a correlated rise in world trade and foreign investment. This signals that perhaps the world is ready for more free trade, eliminating tariffs and other trade barriers.

The Obama administration continues to place an emphasis on implementing carbon rules[6] to address global warming. The EPA described a number of pathways to compliance in its final rule on section 111(d); one of which is a mass-based cap and trade approach which was implemented in the Global Economy scenario.

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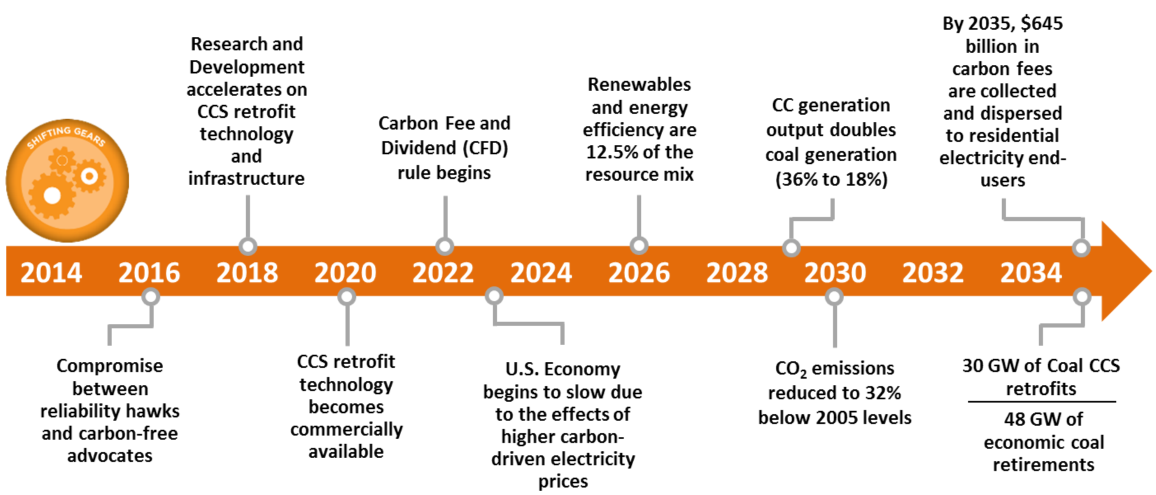
[5] *The Trans-Pacific Partnership*, President Obama, July 2015
[6] *EPA Clean Power Plan Final Rule*, EPA Administrator, Gina McCarthy, August 3, 2015

10.2.4 Shifting Gears Storyline/Timeline

Shifting Gears represents a compromise scenario between reliability hawks, Congress, environmentalists, consumer advocates, and the EPA. The requirement of a 32% reduction in CO_2 emissions from the 2005 level by 2030 is met through a carbon tax on all power sector carbon emissions. This action, referred to in the scenario as the *Carbon Fee and Dividend* (CFD) Rule places the collected fees in a Carbon Fee Trust Fund to be rebated to retail electricity consumers.

As part of the compromise, environmentalists agree to suspend their opposition to natural gas generation and fracking, paving the way for more combined cycle units. Reliability hawks, who fear a carbon compliance strategy which relies too heavily on renewables and energy efficiency will jeopardize grid stability, encourage existing coal unit retrofits with carbon capture and sequestration (CCS) when economically feasible to maintain fuel diversity. While the tax rebate assists the residential electric consumer, the carbon tax fueled higher electricity prices, which deal a blow to the commercial and industrial end users. Consequently, the U.S. experiences pedestrian economic growth in this scenario.

Figure 14 Shifting Gears Timeline



<u>Shifting Gears Signposts</u>

IMPA stakeholders identified a number of signals that indicate the Shifting Gears scenario is a plausible future. The ISO/RTO Council (IRC)[7] has been actively working with the EPA to ensure electric system reliability is taken into consideration as part of any carbon rule making. While the IRC does not ordinarily weigh in on EPA policy issues, the significance of the paradigm shift imposed by capping carbon warranted participation by the IRC on this very important issue.

For carbon compliance, implementing a carbon tax[8] has been floated about for many years, primarily due to its simplicity and transparency. A basic carbon tax, like most consumption taxes which harm lower-income consumers, is addressed by providing residential rebates.

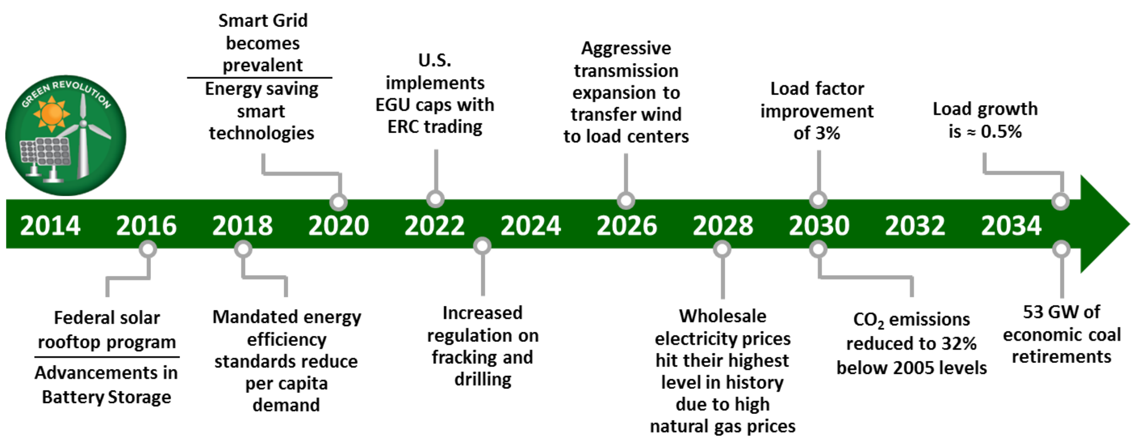
[7] *EPA CO_2 Rule – ISO/RTO Council Reliability Safety Value and Regional Compliance Measurement and Proposals*, ISO/RTO Council
[8] *Bottom Line on Carbon Taxes*, World Resources Institute, Eliot Metzger, July, 2008

10.2.5 Green Revolution Storyline/Timeline

In the Green Revolution scenario, the electricity industry undergoes dramatic changes driven by new innovations, technology, and consumer preference. Utilities experience significant load destruction, primarily due to residential rooftop solar with battery storage, micro grids, and stringent energy efficiency standards for lighting, appliances, HVAC, motors, and building codes. Utilities experience some load growth as electric vehicle sales increase to meet future transportation sector CO_2 emission and miles per gallon targets. A shift in time-of-day power usage improves the overall system load factor by 3% by 2030. In this scenario, utilities see significant cost shifting from electricity production to transmission and distribution to accommodate the smart grid infrastructure.

To meet the EPA's CPP requirement of a 32% reduction in carbon emissions from the 2005 level by 2030 a CO_2 rate cap is implemented beginning in 2022 on affected electric generating units (EGUs). The rate-based approach is one path to compliance offered by the EPA. The affected units would be able to lower their CO_2 emission rate by adding zero-emitting wind and solar emission rate credits (ERCs) to the denominator resulting in a lower CO_2 rate.

Figure 15 Green Revolution Timeline



Green Revolution Signposts

IMPA stakeholders identified a number of signals that indicate the Green Revolution scenario is a plausible future. Technology advancements and consumer excitement for rooftop solar and battery storage, coupled with generous incentives[9] may well lead to significant utility load destruction and load pattern changes. Further, technological advancements in smart grid technology, together with federal incentives[10] have led to increasing investments in advanced metering infrastructure (AMI).

[9] *President Obama Announces New Actions to Bring Renewable Energy and Energy Efficiency to Households across the Country*, The White House, August 24, 2015
[10] *Advanced Metering Infrastructure and Customer Systems*, smartgrid.gov, U.S. Department of Energy

Table 9 Scenario Drivers

	Status Quo	Retrenchment	Global Economy	Shifting Gears	Green Revolution
Description	Base case driven by existing policies and technologies	Shift back to traditional low cost, non-intermittent resources to address global competiveness and reliability concerns	World economy drives higher energy needs placing upward pressure on commodity prices	Steady movement towards sustainable energy as a compromise between pro-coal and non-carbon advocates	Load shifting and destruction through technology advances with strict regulatory policies
Economic Growth	EIA Reference	Medium-High due to lower energy prices and abundance of NG	High as U.S. & World economy booms	Medium-Low due to higher energy prices	Low due to higher energy prices
Capital Construction Cost	EIA Reference	Low due to cheaper resources driven by under-utilized manufacturing capacity	Medium-Low due to cheaper world market for resources	Medium-High due to scarce resources	High due to increased regulations and scarce resources
Electricity Demand - before EE	Reference ~1%	Medium-High	High	Medium-Low	Low
Load Factor	Existing	1.5% higher due to resurgence of high load factor industrial base	1.5% lower due on peak more service oriented businesses	3% lower by 2030 due to loss of high load factor industrial base	3% higher by 2030 due to impact of residential rooftop solar and batteries
Energy Efficiency	Current State Guidelines, RTO Capacity Credit	No capacity credit, repeal state guidelines, economic EE	State guidelines, economic EE	State guidelines, No capacity credit, economic EE	High - Federal EE standards and programs (embedded in load forecast)
Natural Gas Supply	EIA Reference	Higher	Higher	Lower due to higher gas usage	Low - fracking legislation decreases supply
Natural Gas Price	Forward Curve blended to EIA Reference Case	Low	Medium-Low	Medium-High	High
Coal Price	EIA Reference	Low	Medium-High	Medium-Low	High
Oil Price	EIA Reference	Medium-Low	Low	Medium-High	High due to increased regulations on fracking and drilling
CO_2 Strategy/Regulation	No National Regulation - Regional plans stay in place	None, regional plans abandoned	CO_2, interstate cap and trade program (massed-based)	National CO_2 Tax	Unit CO_2 Rate Cap (rate-based)
Environmental Regulation	MATS, CSAPR, Coal Ash, 111(b). CPP not implemented – announced plant retirements	MATS, CSAPR, Coal Ash in place. 111(b) & 111(d) revoked. No major new regulations on generation or drilling/mining	MATS, CSAPR, Coal Ash, 111(b), 111(d)	MATS, CSAPR, Coal Ash, 111(b), 111(d)	All current, plus additional regulations.

	Status Quo	Retrenchment	Global Economy	Shifting Gears	Green Revolution
Emission Caps	Existing CSAPR/MATs - no CO_2	Existing CSAPR/MATs - no CO_2	Existing CSAPR/MATs - 32% CO_2 by 2030 - Cap and Trade (mass-based)	Existing CSAPR/MATs - 32% CO_2 by 2030 - CO_2 Tax	Existing CSAPR/MATs - 32% CO_2 by 2030 – Unit Rate Cap (rate-based)
Nuclear Generation	Retire existing at 60 years, under construction 5.5 GW, economic new builds	Retire existing at 60 years, under construction 5.5 GW, economic new builds	Retire existing at 60 years, under construction 5.5 GW, economic new builds	Retire existing at 60 years, under construction 5.5 GW, economic new builds	Retire existing at 60 years, under construction 5.5 GW, economic new builds
Renewable Generation	Current Statewide RPS plus economic renewable	No capacity credit, repeal state RPS, economic renewable	Current state RPS remain, no new state or national RPS - economic renewable	Current state RPS remain, economic renewable but limited for reliability	Current state RPS remain, no new state or national RPS - economic renewable
Technology Improvements	Current	Current	Battery, smart grid, EE, EV, Mass Trans	Battery, smart grid, EE, EV, Mass Trans	Intense battery, smart grid with federal incentives, DR, EE - federal standards
Coal Generation	Units retire at 75 yrs. 111(b) prohibits new non-CCS coal	Units retire at 75 yrs. repeal of 111(b), economic conventional coal	Units retire at 75 yrs., economic retirements and CCS retrofits	Units retire at 75 yrs., economic retirements and CCS retrofits	Units retire at 75 yrs., economic retirements
Reserve Margin	Pool Requirements + 1%	Pool Requirements + 2%	Pool Requirements	Pool Requirements + 2%	Pool Requirements + 3%
Transmission	More due to aging transmission infrastructure	More due to aging transmission infrastructure	Much more due to aging transmission infrastructure and increased renewable/intermittent generation	Much more due to aging transmission infrastructure and increased renewable/intermittent generation	Much more due to aging transmission infrastructure and increased renewable/intermittent generation
Wholesale Electricity Price	Medium-Low	Low due to low fuel prices	Medium due to cap and trade carbon market prices	Medium-High due to carbon tax	High due to unit carbon cap and high fuel prices
Wholesale Capacity Price	Medium-High	Medium-Low due to higher pool requirements and low capital costs	High due to lower pool requirements than the other scenarios	Medium due to higher pool requirements and medium-high capital cost	Low due to highest pool requirements and highest capital costs

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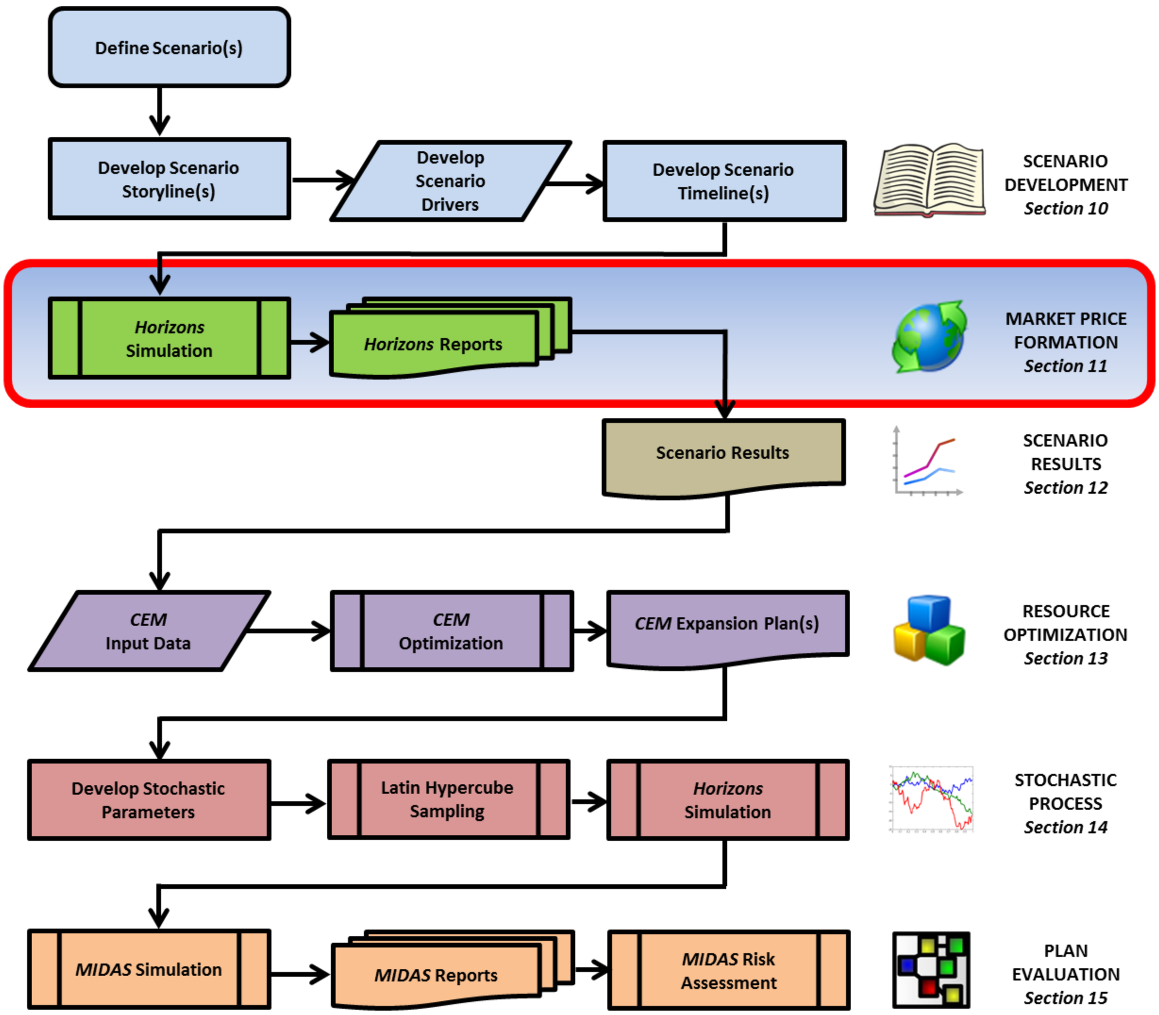
11 MARKET PRICE FORMATION

Once the scenario storylines, timelines, and drivers have been developed, the next step is to make the scenarios actionable by modeling their unique characteristics in the Horizons Interactive Market Module. For each scenario, the drivers and regulations are simulated with the hourly chronological market model to determine the corresponding wholesale price for electricity, capacity, and the shadow price for CO_2.

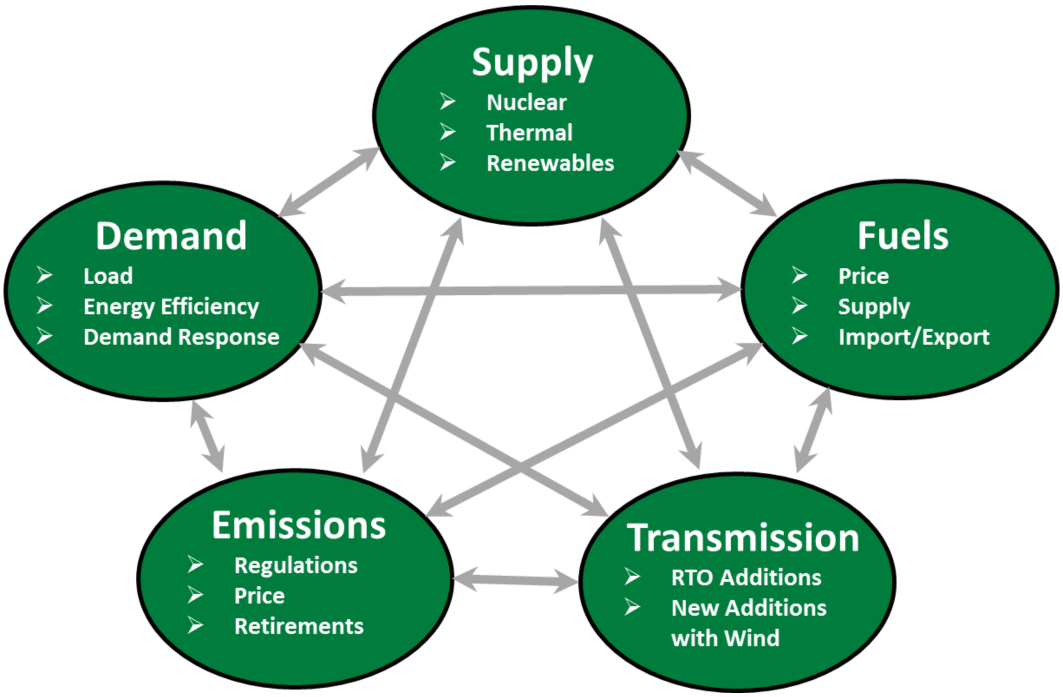
Figure 16 IRP Flowchart – Market Price Formation



With the implementation of the RTO energy and capacity markets, the future cost of market power and energy is one of the most critical aspects of utility planning. No longer can utilities simply plan as islanded entities, building for their own load in a vacuum. Planning must incorporate a reasonable and realistic forward view of the market.

IMPA utilizes market price projections for all planning activities, from short term hedging decisions to long term planning. The integrated modeling approach creates a fundamental forecast that is internally consistent across supply, demand, fuels, emissions, and transmission. This section of the report discusses IMPA's methodology for creating the market price forecasts used in various aspects of its planning processes.

Figure 17 Integrated Market Modeling Process



Source: IMPA

11.1 Horizons Interactive Module

The Horizons Interactive Market Module performs an hourly, chronological, calendar-correct simulation which iteratively considers the market dynamics of power, fuels, transmission, emissions, and renewables.

The model database includes all North American generating assets, hourly loads, transmission interties, fuel supply, etc. The created market prices for energy and capacity are easily transferable to the Capacity Expansion and MIDAS Gold modules.

Figure 18 Horizons Interactive Cut Sheet

Horizons Interactive

The ***Horizons Interactive*** market module allows you to produce fast and comprehensive market fundamental analysis. Populated with the ***Velocity Suite*** market leading North American database of generating units, transmission, and load, it can be used to identify key market trends and drivers.

Integrated Markets

Integrated Markets is an hourly, chronological, calendar-correct market model which iteratively considers the market dynamics of power, fuels, transmission, emissions, and renewables. The model database includes all North American generating assets, hourly loads, transmission interties, fuel supply, pipelines, etc. The market prices for energy and capacity are easily transferable to the ***Capacity Expansion Module*** and ***MIDAS Gold®***.

Market Sampler

Market Sampler is a flexible, statistically reliable Latin-Hypercube (LHS) sampling program that generates future scenarios by taking a series of equal-probability, random draws from among possible future values of uncertainty.

Market Match

Market Match is a fast, robust, post-processing tool that combines statistical and fundamental analysis within a consistent planning framework. ***Market Match*** adjusts a set of multi-scenario ***Horizons Interactive*** model- derived market prices to conform to OTC forwards and options providing a market to model capability. ***Market Match*** provides an ability to sculpt hourly ***Horizons Interactive*** zonal prices to nodal prices using user defined basis, volatility, and correlation.

Horizons Interactive Market Module

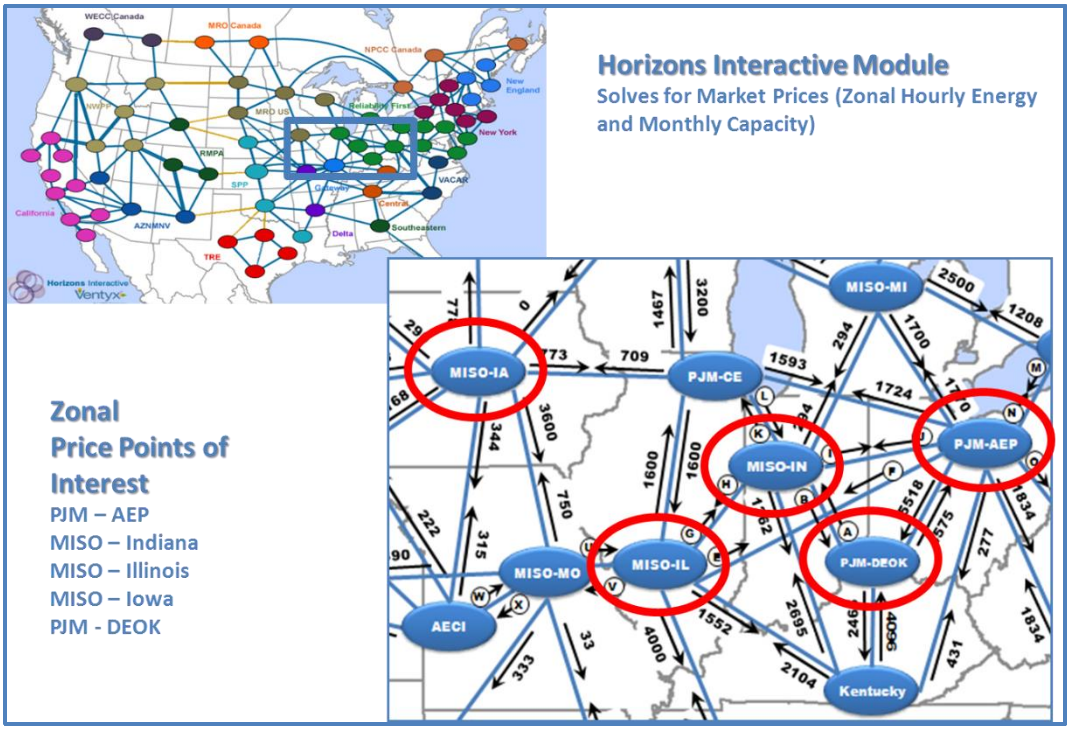
Source: Ventyx

Zonal Markets

As a market participant with generation and load in both the MISO and PJM, IMPA is interested in forward energy and capacity price curves for five market zones (3 in MISO and 2 in PJM) where IMPA has resources and load.

- PJM – AEP (AEP-DAYTON HUB)
- MISO – Indiana (INDIANA HUB)
- MISO – Illinois (ILLINOIS HUB)
- MISO – Iowa (IOWA ZONE)
- PJM - DEOK (DEOK ZONE)

Figure 19 Zonal Price Points of Interest



Source: Horizons Interactive Database

Bid Behavior

Power prices are formed each hour, based on the bids submitted by individual generators. In general, the marginal unit determines the market clearing price where a unit's bid includes variable costs such as fuel, emissions, and variable operation and maintenance (O&M). In practice, generators employ a wide variety of strategies that are consistent with the cost characteristics of their generating portfolio. Conversely, RTOs forecast demand and run a security-constrained, least-cost dispatch model to select which generators to run to meet the load subject to transmission and other system security constraints.

During high load hours, there may be barely sufficient generation to meet loads. During these times, the revenue collected by individual generators increases with the scarcity and congestion present in the market and can, over time, contribute significantly to the coverage of financing and other fixed costs. The collection of scarcity revenue is consistent with a functioning market, providing a price signal to the market that additional resources may be necessary.

Congestion/Scarcity Function

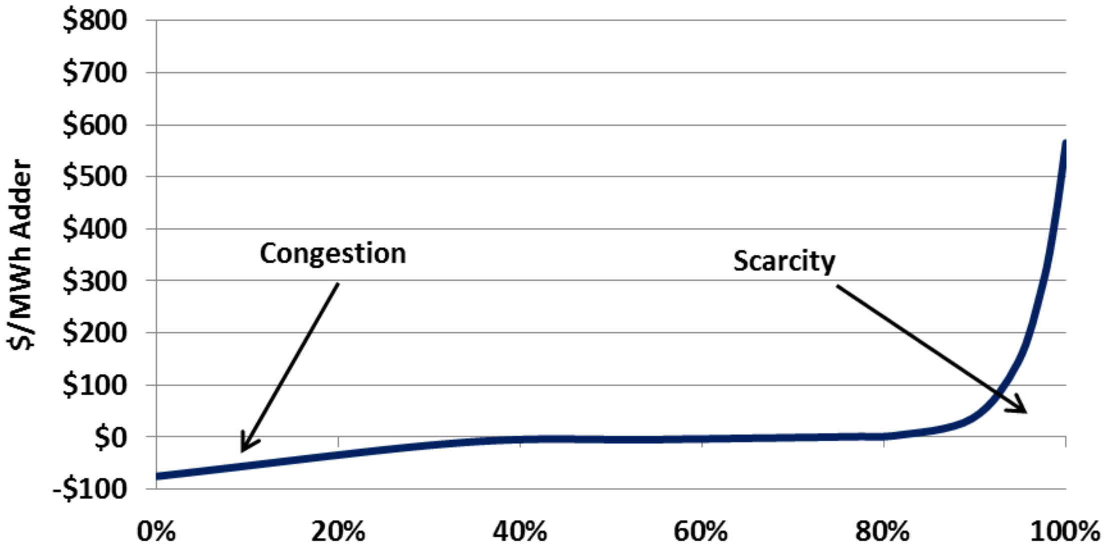
To capture the market bid behavior, a congestion/scarcity function is added to the system marginal cost curves. A "typical" congestion/scarcity function is shown on the next page. This function is for illustrative purposes only as the actual function(s) are calibrated to mimic the bid behavior of each zone in Horizons Interactive. The inflection points of the curve are adjusted to meet the bid behavior and specific resources in each zone.

For example, the scarcity inflection point for a zone with 95% coal generation would slide far to the right as this zone is price-taker, thus scarcity would likely not be added to their bid. Conversely, the scarcity inflection point for a zone with 50% combustion turbines would slide to the left as this zone would collect scarcity to recover a portion of their start-up and fixed costs else they would prefer not to run the combustion turbines.

The congestion inflection point reflects the impact of low or even negative LMPs. In zones with high congestion, which is often linked to wind generation, the price signal at times may be below marginal cost or even below zero to incent generation to either back down or shut down. The negative bid behavior is driven by the PTC, which incent wind units to run at a marginal loss because they still receive payment in the form of tax credits for each MWh generated. When the PTCs expire, it is expected there will be far less negative bid behavior.

In 2013, MISO implemented its Dispatchable Intermittent Resources (DIR) initiative, which allows renewable generation to be treated like any other generation resource in the market and, for the first time, participate in the region's real-time energy market. Now wind can automatically be dispatched within a designated range based on an offer price and wind conditions. This enables wind to submit offers and receive dispatch instructions rather than be manually curtailed when transmission constraints limit renewable energy generation to reach the broader market region.

Figure 20 Congestion/Scarcity Function



Source: IMPA

Horizons Interactive - Market Database

The Horizons Interactive database is populated with Ventyx Velocity Suite – Market Ops information.

- Operational information is provided for over 11,000 generating units
    - Heat Rates
    - Emissions
    - Forced Outage (FO)/Maintenance Outage (MO) Rates
- Load forecasts by balancing authority and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub with basis and delivery adders

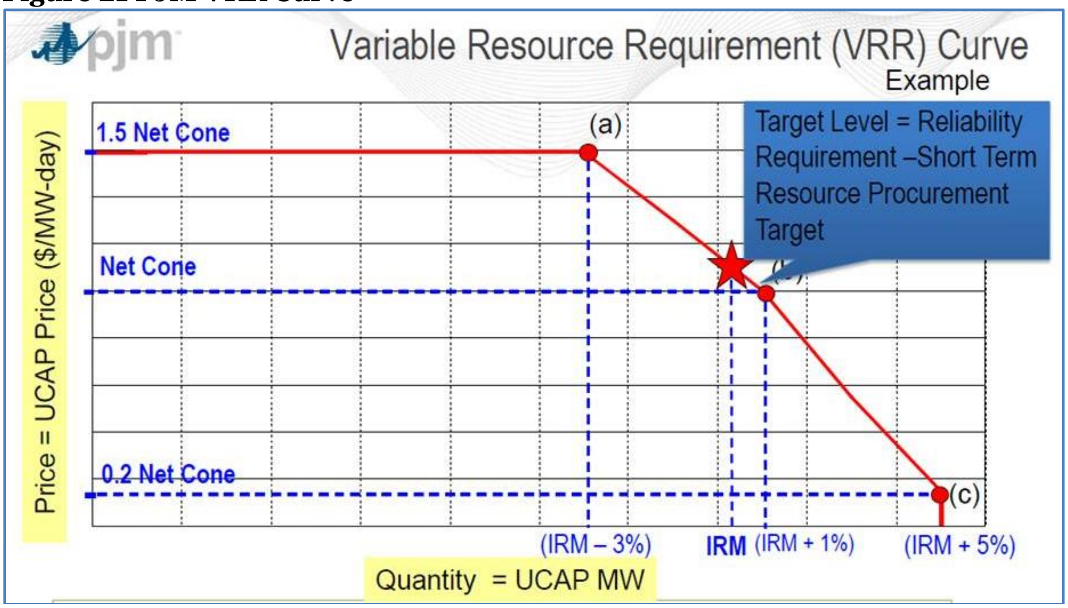
When running the simulation in Horizons Interactive, the main process of the simulation is to determine hourly market prices and monthly capacity prices. Unit outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled as is the case for nuclear unit refueling schedules.

Resource Expansion

The market-based resource expansion algorithm builds resources from a list of candidate resources based on unit profitability and minimum reserve margin requirements as defined by the capacity demand curve constructs. Non-profitable units are retired based on three consecutive years of failing to recover fixed operating costs.

The market-based resource expansion algorithm is an important aspect of Horizons Interactive as it dynamically adds resources consistent with the rules of the prevailing RTO. For example, PJM utilizes the cost of new entry (CONE) and a variable resource requirement (VRR) curve as shown in the figure below while MISO uses a resource adequacy requirements (RAR) curve.

Figure 21 PJM VRR Curve



Source: PJM

Zonal Simulation Process

The Horizons Interactive simulation process performs the following steps to determine price:

- Hourly loads are summed for all customers within each zone.
- For each zone in each hour, all available hydro and load modifying renewable power is used to meet firm power sales commitments.
- For each zone and day type, the model calculates production cost data for each dispatchable unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each zone considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among zones.
- The model records and reports details about the generation, emissions, costs, revenues, etc., associated with these hourly transactions.

Nodal Simulation Process

As discussed earlier in this section, IMPA uses Horizons Interactive to solve zonal energy prices for large geographic regions, at a minimum the entire Eastern Interconnection, and often all eight NERC regions. The reason for solving large regions is to capture the full impact of policies (EPA rules, legislation, renewable portfolio standards, etc.) as well as impacts of commodity price swings (natural gas, coal, SO_2, NO_x, CO_2, etc.).

IMPA operates in the MISO and PJM RTOs, which utilize nodal energy prices. Nodal prices are determined by matching offers from generators to bids from consumers at each node to develop a supply and demand equilibrium price on an hourly interval.

The price of electricity at each node on the network is a calculated "shadow price", in which it is assumed that one additional megawatt-hour is demanded at the node in question, and the incremental cost to the system that would result from the optimized redispatch of available units establishes the production cost of the megawatt-hour. This is known as nodal or locational marginal pricing (LMP).

There are two generally accepted nodal solutions.

- Security-constrained economic dispatch solution (SCED)
- Zonal flow gate constrained economic dispatch with Nodal Algebraic Model solution (NAM)

SCED: This is the more detailed and resource intensive solution. To create LMPs, MISO and PJM incorporate a security-constrained, least-cost dispatch calculation with supply based on the generators that submitted offers and demand based on bids from load-serving entities at the nodes in question in 5-minute intervals. Where constraints exist on a transmission network, there is a need for more expensive generation to be dispatched on the downstream side of the constraint. Prices on either side of the constraint separate, giving rise to congestion pricing. Both RTOs use proprietary software for the creation of LMPs and are generally interested in the formation of day-ahead and real-time LMPs, which creates the transparent energy market.

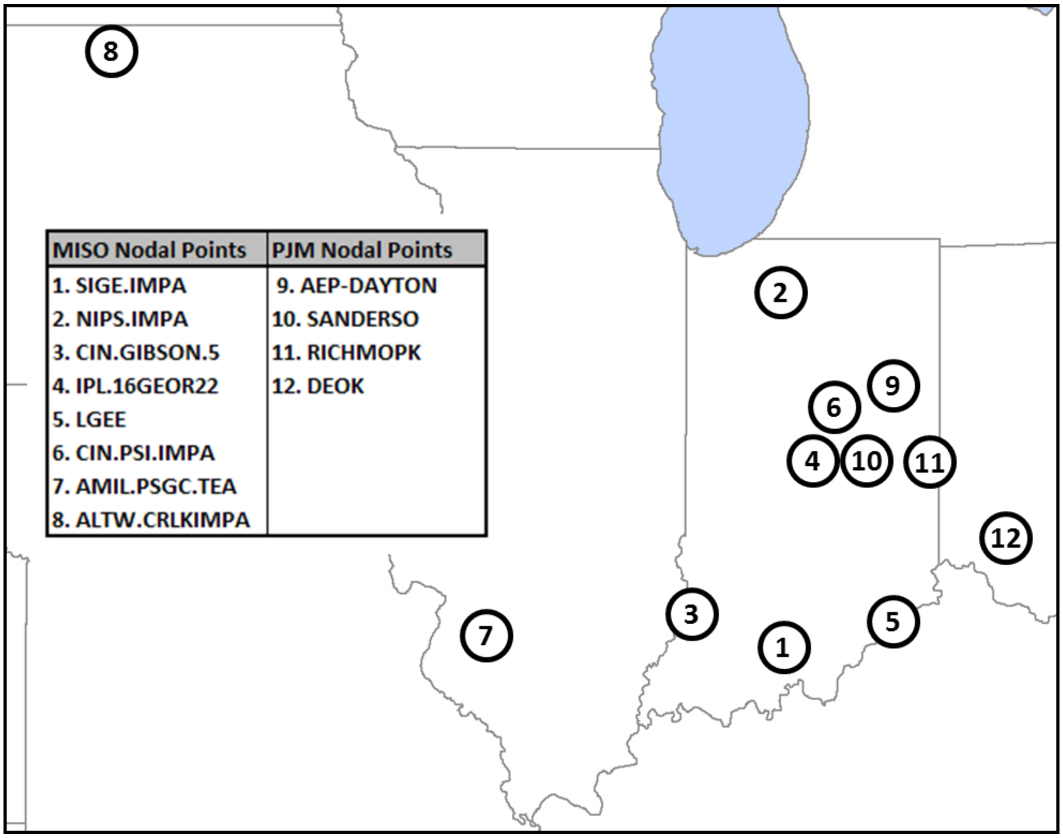
For long-term planning, security-constrained economic dispatch models require detailed knowledge and assumptions of the resources, load, and transmission system. The transmission system is modeled as either an AC or DC power flow simulation to forecast congestion. Unfortunately, SCED models are generally limited to a minimal number of scenarios and years due to the computational time requirements of the software and hardware making it difficult to perform stochastic analysis or even a few scenarios in a timely fashion.

NAM: The NAM technique uses the zonal topology described earlier in this section to solve for zonal hourly market clearing prices for multiple scenarios and years across the entire North American electricity footprint where zones are separated by flow gate transmission constraints. For the formation of nodal prices, an algebraic solution is applied using historical volatility, correlations, and basis spreads between the zonal and nodal points of interest. For long-term planning this technique has enormous benefits as it accommodates multiple scenarios and years.

IMPA's methodology is to solve for zonal prices and then apply algebraic hourly spreads to the zonal price to create nodal prices. While this method relies heavily on past historical basis spreads, correlation, and volatility, it is flexible enough to incorporate adjustments to reflect changes in the resource mix and transmission infrastructure. Since IMPA is interested in 50 stochastic simulations for 20 years, the NAM technique is the preferred solution.

IMPA is generally interested in the following nodal prices.

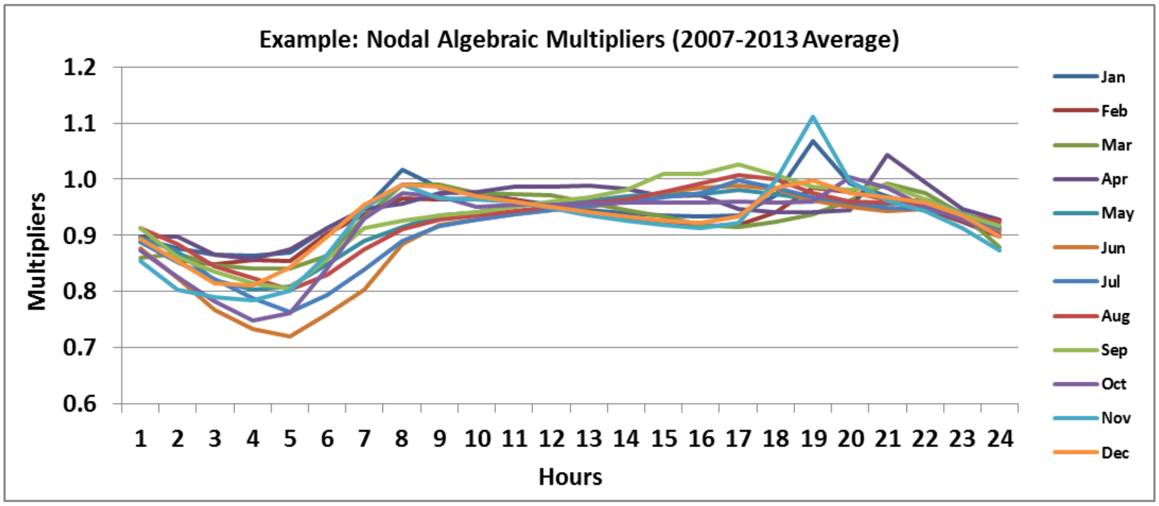
Figure 22 Nodal Price Points of Interest



Source: IMPA

Nodal Algebraic Multipliers: The following figure illustrates an example of the algebraic multipliers for a given node by time-of-day and month. These multipliers are applied to the zonal forecast in the zone in which they reside.

Figure 23 Nodal Algebraic Multipliers



Source: IMPA

11.2 HORIZONS INTERACTIVE PROCESS

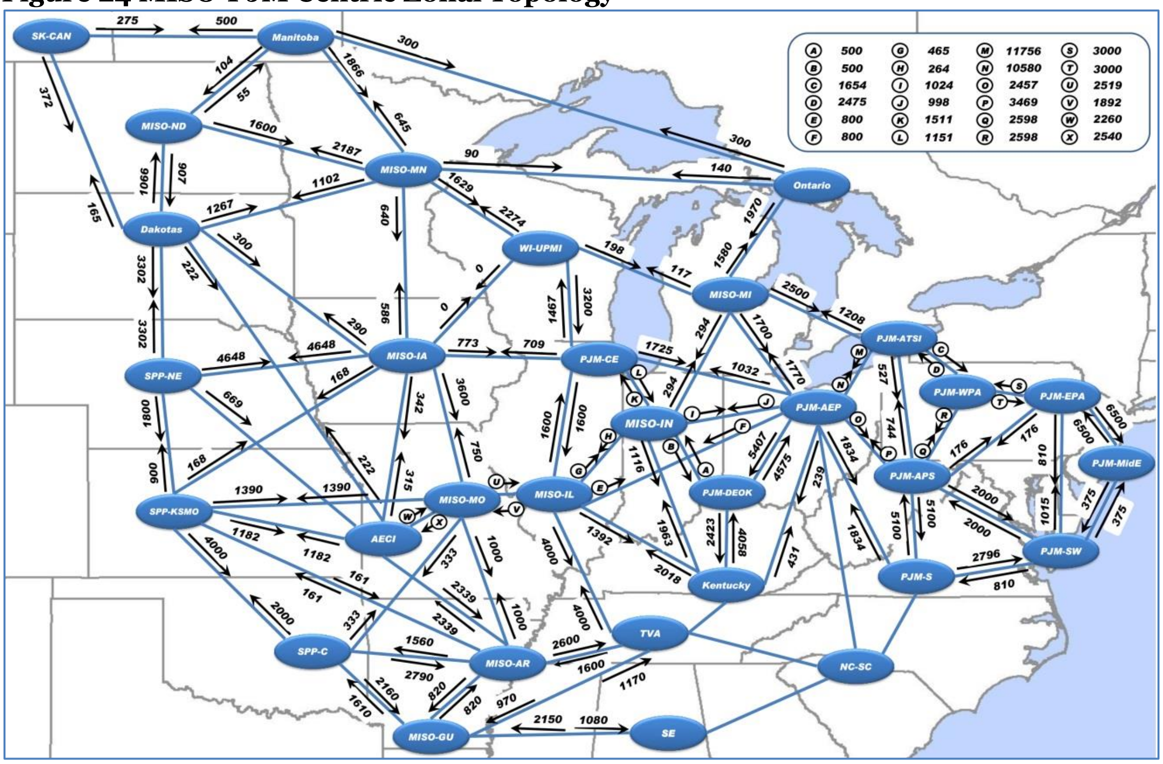
The formation of market energy and capacity prices begins with a reference case to reflect baseline assumptions for fuel, loads, transmission, congestion, environmental policy, retirements, etc. The reference case is also commonly referred to as the deterministic case. In this report, all forecasts are in current ("nominal") dollars. The study period is defined as 2016-2035.

Forward View Approach

IMPA created a forward view of the MISO and PJM electricity markets. The forward view is a proprietary perspective of the future based on public or commercial information and IMPA's experience in working in electricity markets. This fundamental approach relies on first identifying the basic components of electricity price: supply, transmission and demand, as well as using the best available sources, projecting the components over time and geography.

The following figure shows the electricity zones and their interconnections.

Figure 24 MISO-PJM Centric Zonal Topology



Source: Horizons Interactive Database

Natural Gas

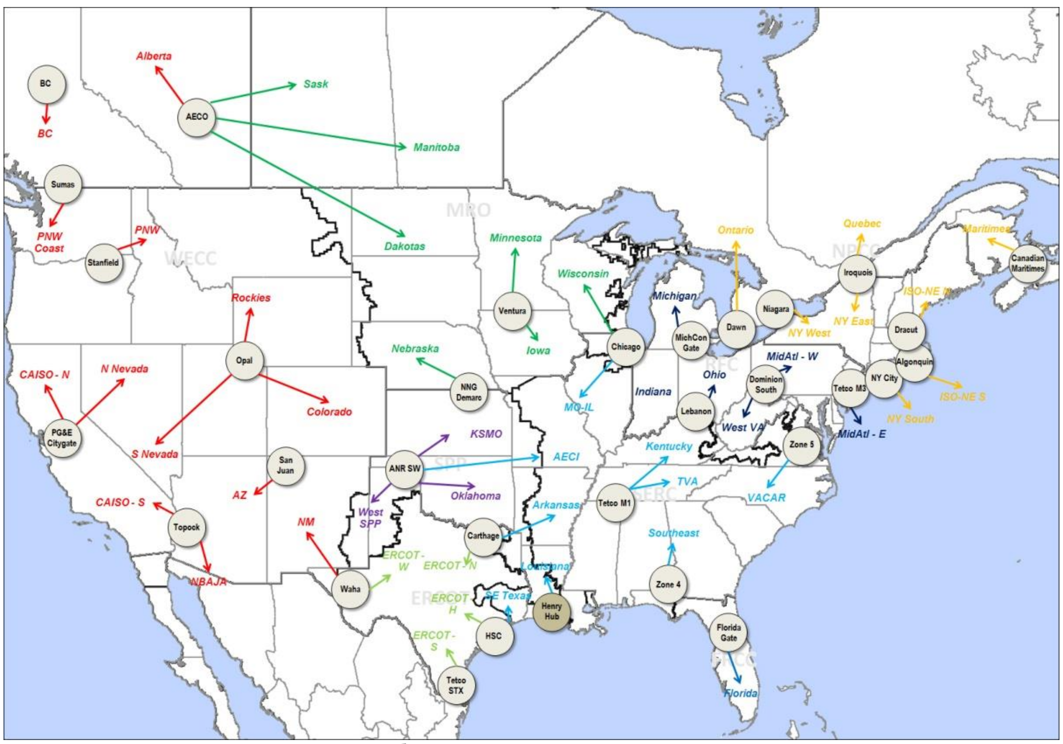
IMPA generated a natural gas price forecast that was representative of the then current NYMEX pricing (July 29, 2015) and blended to EIA's AEO2014 forward view.

Table 10 Natural Gas Outlook

Forecast Phase	Period Length	Data Source	Forecast Technique
Futures Driven	First 79 Months (Jan 2016 -July 2022)	NYMEX Henry Hub futures (July 29, 2015)	Calculated Henry Hub and liquid market center differentials
Long-term Trend	Remaining forecast period (to 2035)	EIA AEO2014	EIA fundamental supply and demand analysis using the NEMS forecasting model

To derive the burner-tip forecasts used, IMPA examined regional prices and basis swaps at a number of trading hubs. Using this data, IMPA developed a differential price between the appropriate market center nearest to the power plant and the Henry Hub.

Figure 25 Natural Gas Market Centers



Source: Horizons Interactive Database

The burner-tip gas price for each gas-fired generation plant in a region is developed by taking the hub price and adding a regional transportation adder. This amount depends on the plant's location relative to the basins or hubs, and the economics of transporting gas, including compressor fuel used and pipeline tariffs/discounts, to the plant's burner-tip. The commodity and transportation components of natural gas burner-tip prices are forecast separately and then assembled to derive the prices paid by generation plants appropriate to their geographic location.

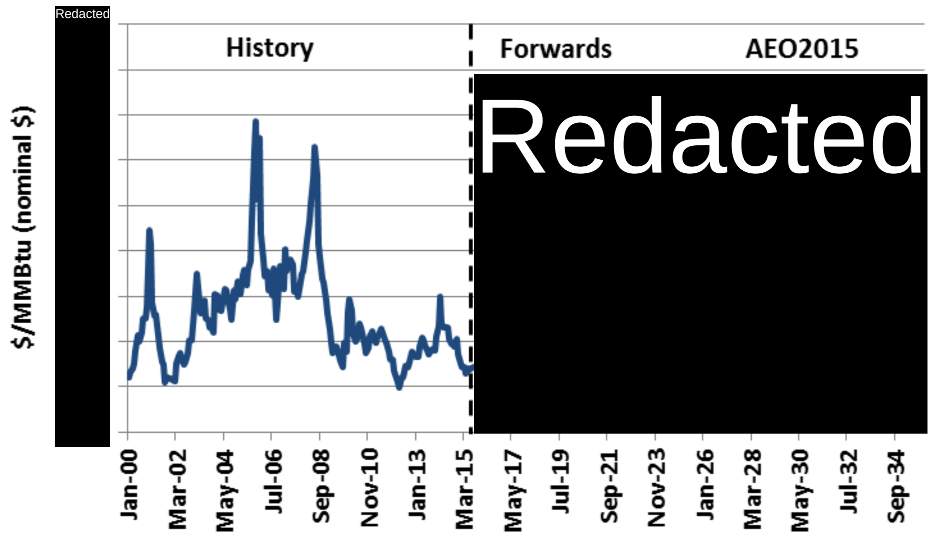
Table 11 Average Delivered Natural Gas Price ($/MMBtu)

	Henry Hub	MichCon Gate	Chicago	Lebanon	Ventura	Dominion South
2016	[redacted]					
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						

Source: IMPA

The blending of the current forward natural gas prices with the long-term EIA2014 reference case forecast projects a compound annual growth rate (CAGR) of [redacted] (see graph on next page). While the EIA fundamental forecast projects a [redacted] (2025-2035), the [redacted] in the 20 year forecast is driven by the transition from forward prices to market fundamental prices. The disparity in forwards and fundamentals is driven by a bearish market for natural gas combined with a bullish market for long-term natural gas fundamentals.

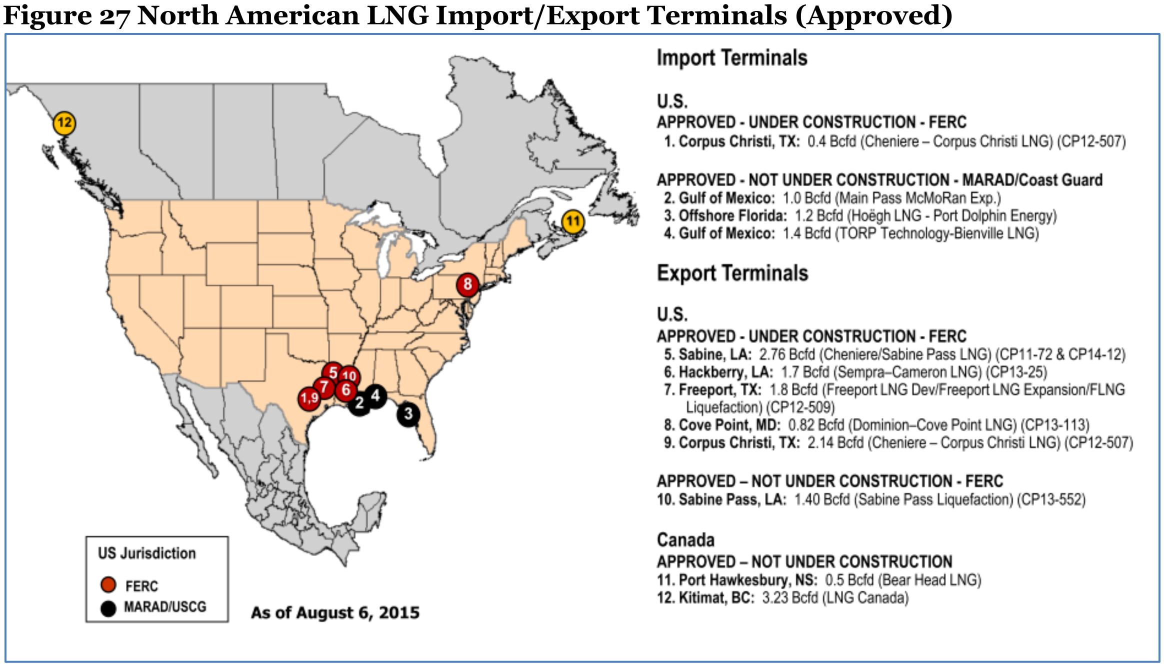
Figure 26 Natural Gas Henry Hub History/Forecast



Source: IMPA

As shown by the historical portion of the graph, the price of natural gas has proven to be a highly volatile. If U.S. natural gas exports increase due to new liquefied natural gas (LNG) facilities, there will likely be an upward pressure on natural gas price as the "world price" of natural gas is on the order of 4 times higher than the present U.S. price. LNG is a clear, colorless, non-toxic liquid that forms when natural gas is cooled to -162ºC (-260ºF). This shrinks the volume of the gas 600 times, making it easier to store and ship. In the graph shown below are the approved North America LNG terminals as of August 6, 2015.

Figure 27 North American LNG Import/Export Terminals (Approved)

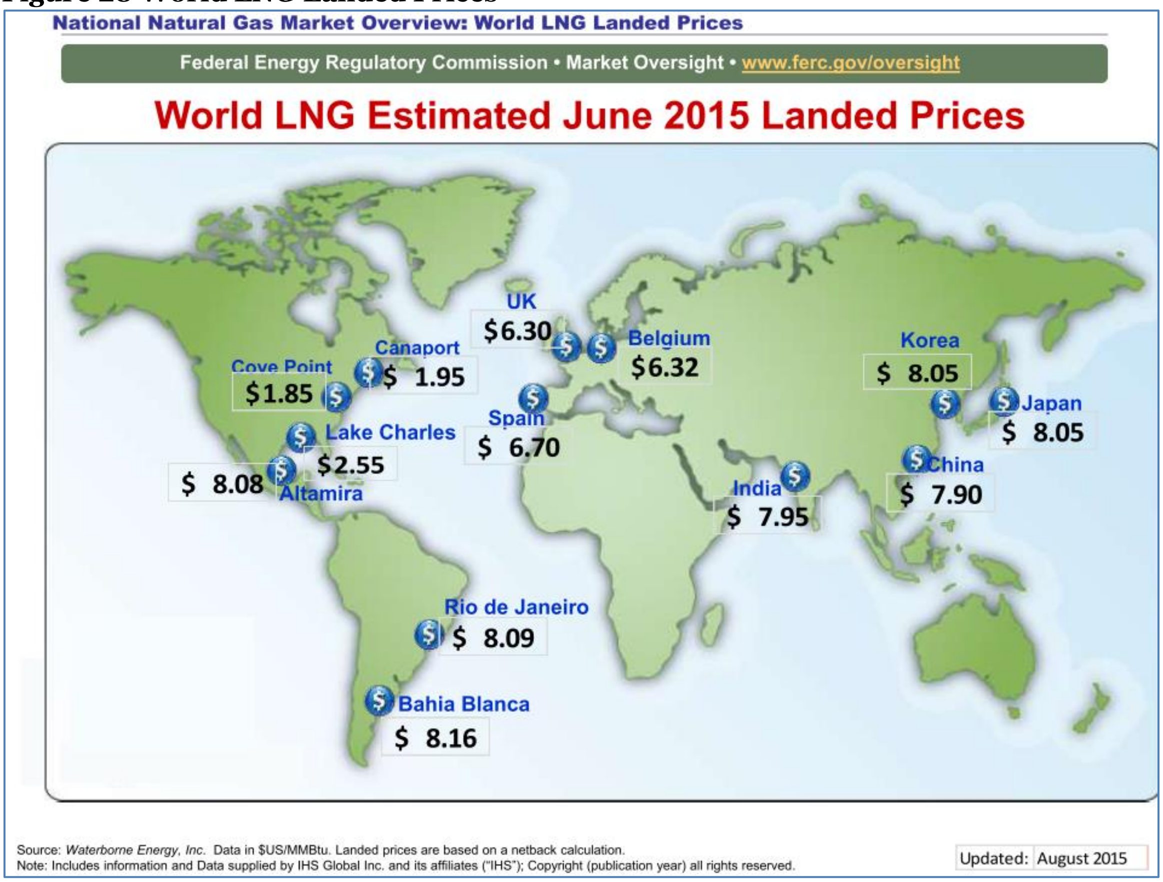


Source: FERC

Natural gas, when in a gaseous state, does not provide a comparable U.S. price to other countries as natural gas can only be transported through pipelines. However, when in LNG form (liquid state), the global price can be compared through a statistic referred to as the "landed price." The price for LNG imports are reported as "landed," received at the terminal, or "tailgate," after regasification at the terminal.

The graph below shows the World LNG landed prices for June 2015. The price of LNG varies considerably from region to region, with a fourfold difference between the U.S. and Japan, as can be seen in the figure below. The largest importers are Japan, South Korea, China, Spain and Taiwan. Regional LNG base prices are influenced mainly by the availability of resources for power generation and security of supply. Thus, the U.S. price is strongly influenced by the country's extraction of low-priced shale gas, while LNG imports to the U.S. are negligible. The low-end prices are found in the United States, the highest in Asia, with European prices in between.

Figure 28 World LNG Landed Prices



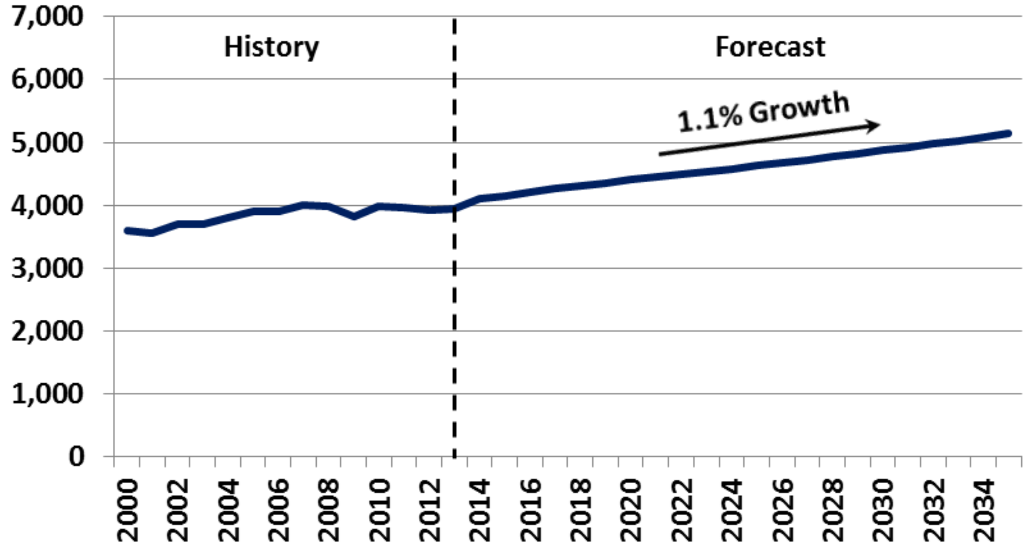
Source: FERC

Horizons Interactive Loads

Monthly peak load and energy forecasts are projected for each balancing authority based on historical values and assumed growth from a variety of public and private sources.

The graph below shows the forward view of U.S. electricity demand.

Figure 29 U.S. Electricity Demand (Energy)



Source: Horizons Interactive Database

Coal Retirements

A significant amount of coal-fired generation either has already been retired or will be retired over the study period largely due to the capital investment required to comply with the EPA's MATS.

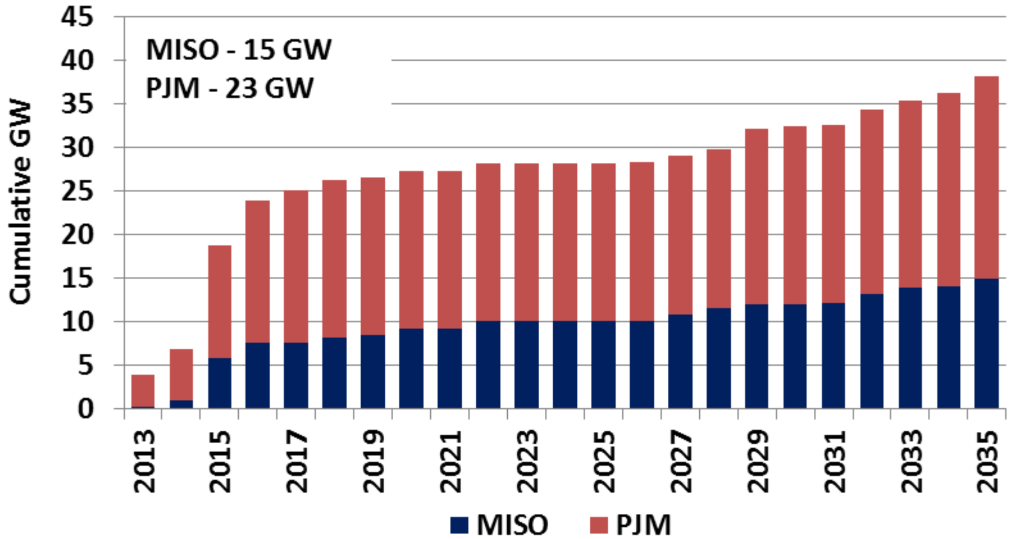
The map below identifies the location of the retired, announced to be retired, or assumed will be retired due to age coal units. From 2013 to 2035, it is assumed that 81 GW of coal capacity will be retired. This <u>does not</u> include any retirements, which will occur for the EPA's CPP compliance. A large share (47%) of the retirements is concentrated in MISO and PJM.

Figure 30 Projected Coal Retirements (2013-2035)

Source: Horizons Interactive Database

The following figure illustrates the actual and assumed coal-fired generation retirements (38 GW) in the MISO/PJM RTOs since 2013. This figure represents about one-quarter of the coal fleet (as of 2012).

Figure 31 MISO/PJM Coal Retirements

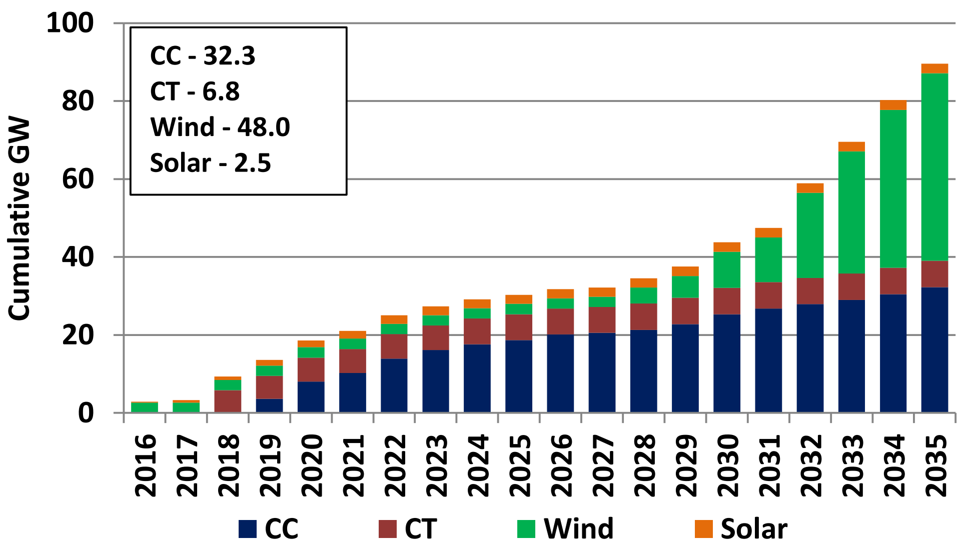


Source: IMPA

Resource Expansion

Announced new generating units plus generic units that were selected by the Horizons Interactive market-based resource expansion algorithm are shown in the graph below for the MISO/PJM RTOs. The units were added to replace retiring coal units and meet projected load growth. The renewable units (wind and solar) were added to meet state-level RPS standards and beginning in 2030, wind installations increase as they became more economical.

Figure 32 MISO/PJM Resource Expansion



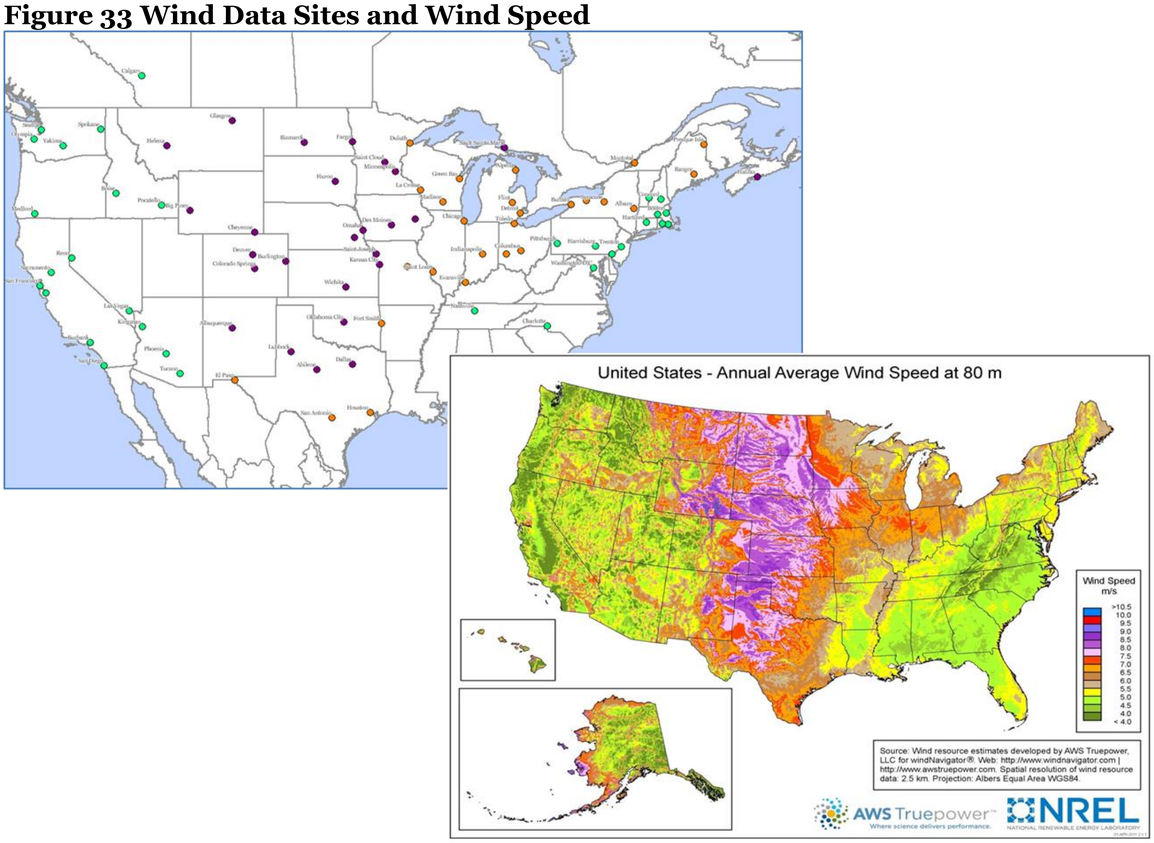
Source: IMPA

Wind

The total wind capacity in the MISO footprint has grown dramatically since 2006. Driven by the nation's desire for cleaner energy and state mandates for renewable energy portfolios, MISO now manages more than 11,000 MW of wind generation in service, with more than 7,000 MW of projects advancing through the interconnection process.

In the absence of publically available hourly wind data for the continental U.S., as a proxy, IMPA utilizes the hourly wind speed at 10 meters at 84 airport sites. The 10 meter hourly wind speed is converted to 80 meter wind speed using a proprietary algorithm, which is consistent with the National Renewable Energy Laboratory (NREL) wind class for that geographic location. The 80 meter wind speed is then converted to MWh using wind power curves.

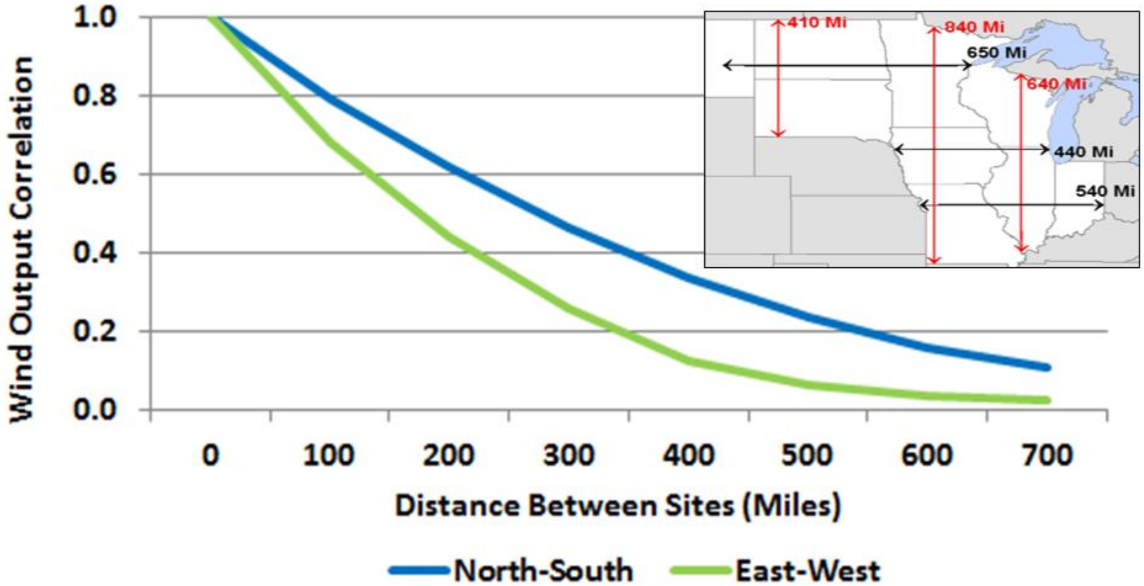
Figure 33 Wind Data Sites and Wind Speed



Source: IMPA/NREL

It is anticipated that wind generation will continue to grow so it is important the availability and geographical correlation of the intermittent wind resources are properly modeled. According to a MISO study, as the distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average hourly output from wind, but a lower hourly maximum across a wide region such as the MISO RTO footprint (see figure on the next page).

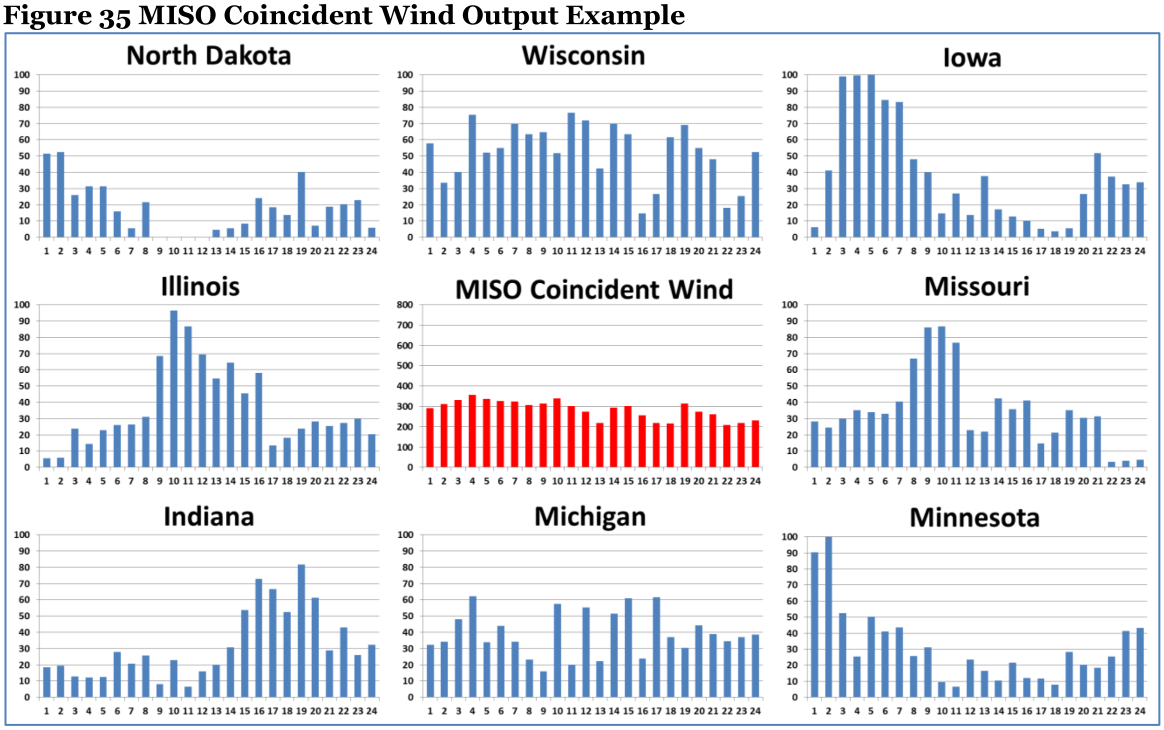
Figure 34 MISO Wind Output vs Distance



Source: MISO

As shown in the graphs below, the wind output for eight 100 MW wind farms spread across the eight northern MISO states can be dramatically different on any given day. In theory, the aggregate hourly output could be as high as 800 MW or as low as 0 MW. However, due to the low wind correlation across a wide geographic footprint described above, the coincident wind output tends to revert to the average. This is an important attribute to consider when modeling wind.

Figure 35 MISO Coincident Wind Output Example

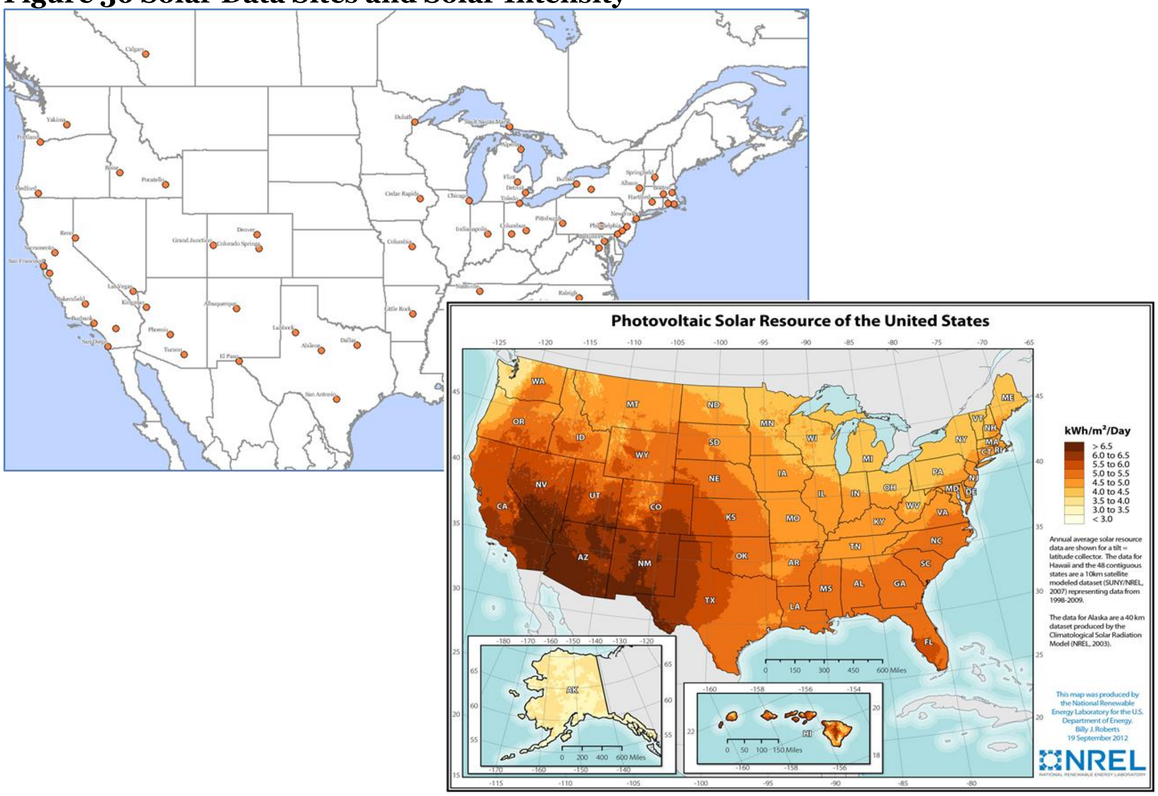


Source: IMPA

Solar

As PV solar installations have become more economical, there has been an increased appetite for utility scale and rooftop solar. To model the output of these installations, IMPA utilizes hourly solar patterns developed by NREL's PV Watts Calculator. It is not anticipated that utility and rooftop solar will grow as quickly as wind due to its low capacity factor.

Figure 36 Solar Data Sites and Solar Intensity



Source: IMPA/NREL

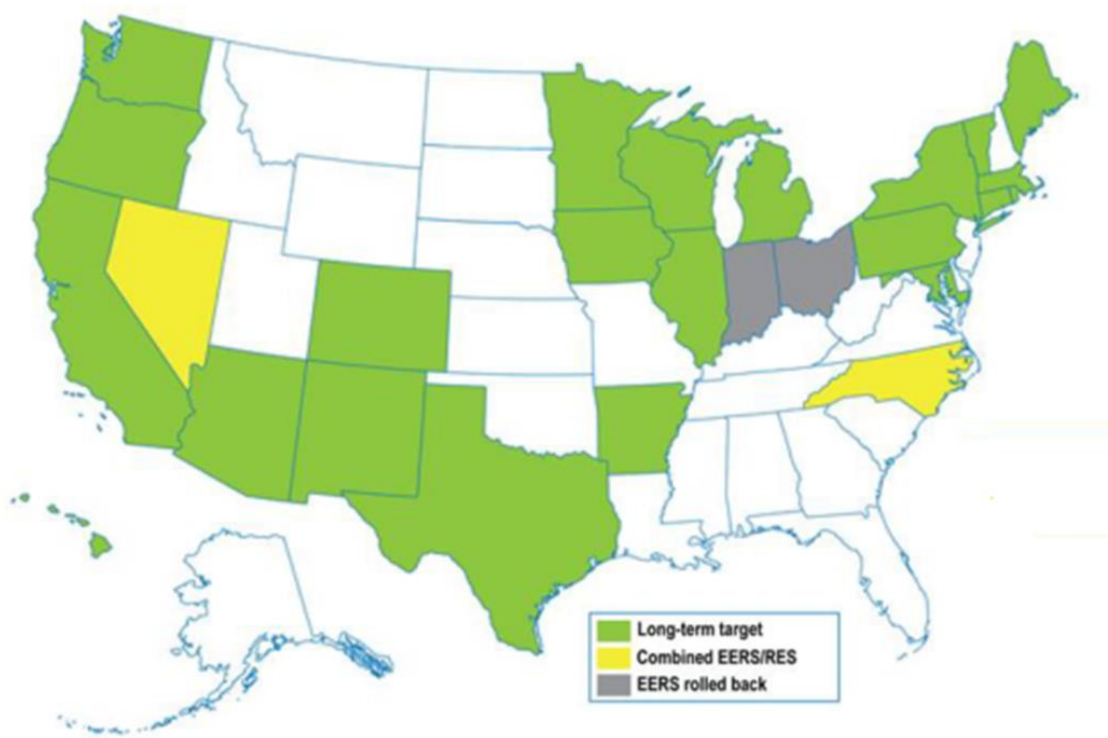
Energy Efficiency

To model energy efficiency and demand response, the Horizons Interactive model considered the sizing and timing of demand-side resources in the same fashion as the model considered supply-side resources.

State Energy Efficiency Resource Standards (EERS)

For states with an energy efficiency resource standard (EERS), the long-term targets of states with EERS polices were met. For states without an EERS policy, the model made an economic choice of when to add energy efficiency.

Figure 37 States with EERS Policies

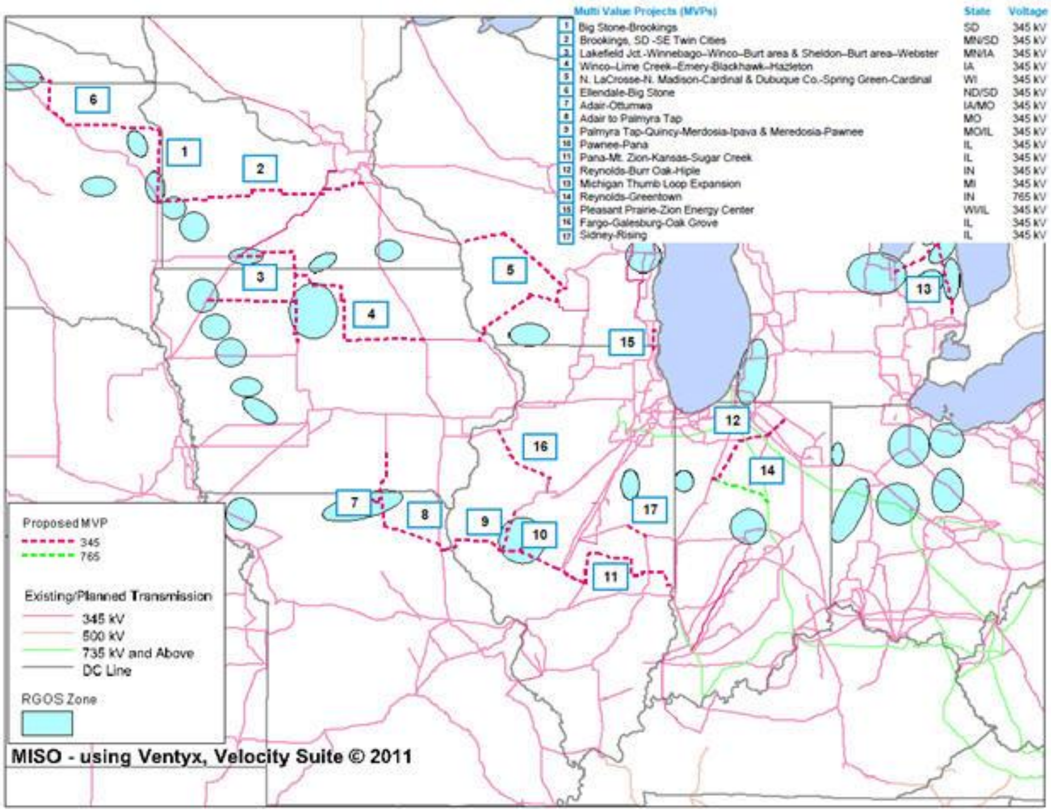


Source: ACEEE

Transmission

The transmission transfer capability between Zones is determined from the most recent AC load flow studies. Likely transmission additions such as the MISO MVP are added to the database to incorporate their impact on the transmission transfer capability and energy and capacity prices.

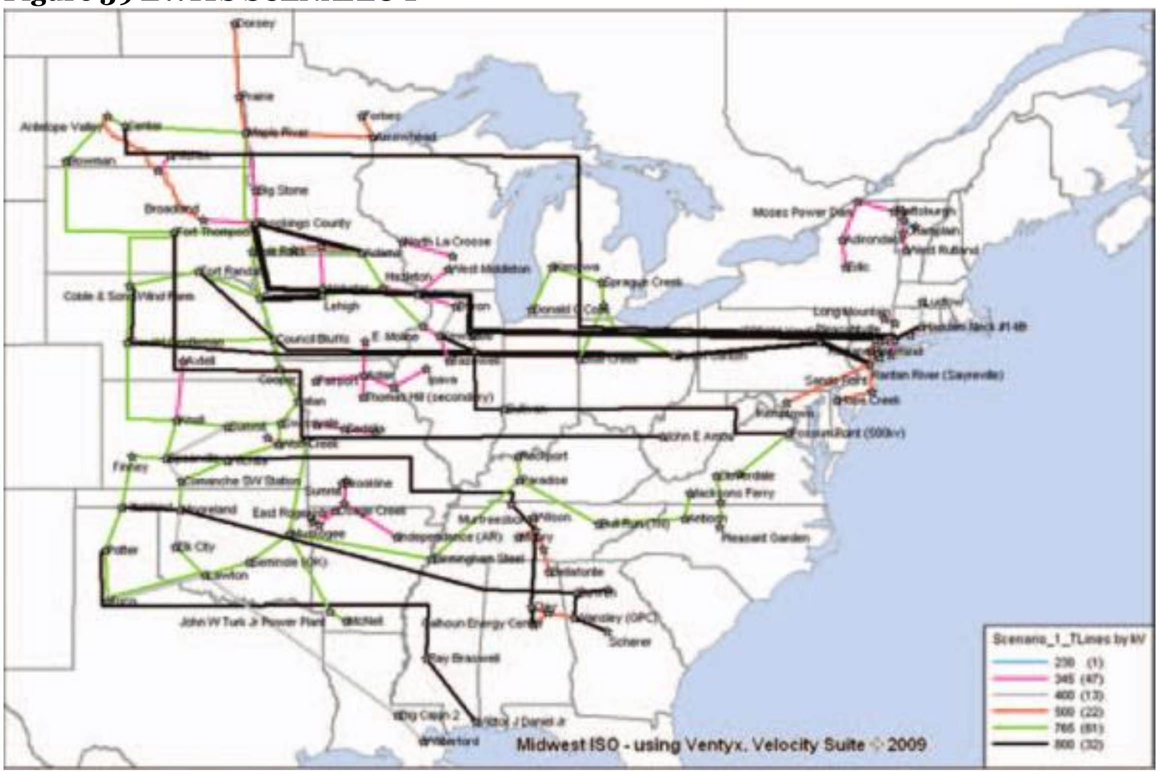
Figure 38 MISO MVP Portfolio



Source: MISO

For the stochastic draws, which include a high level of wind penetration, IMPA utilized the *Eastern Wind Integration and Transmission Study* (EWITS) prepared for NREL by EnerNex Corporation. The study focused on what transmission would be needed to facilitate 20% and 30% wind penetration levels across the Eastern Interconnection. The architecture designed by EnerNex used a mix of multiple high-voltage direct current (HVDC) and extra high-voltage alternating current (EHVAC) lines to move wind power from the western wind areas to the eastern load centers. EWITS Scenario 1 planned for additional transmission to accommodate 225 GW of onshore wind capacity.

Figure 39 EWITS SCENARIO 1

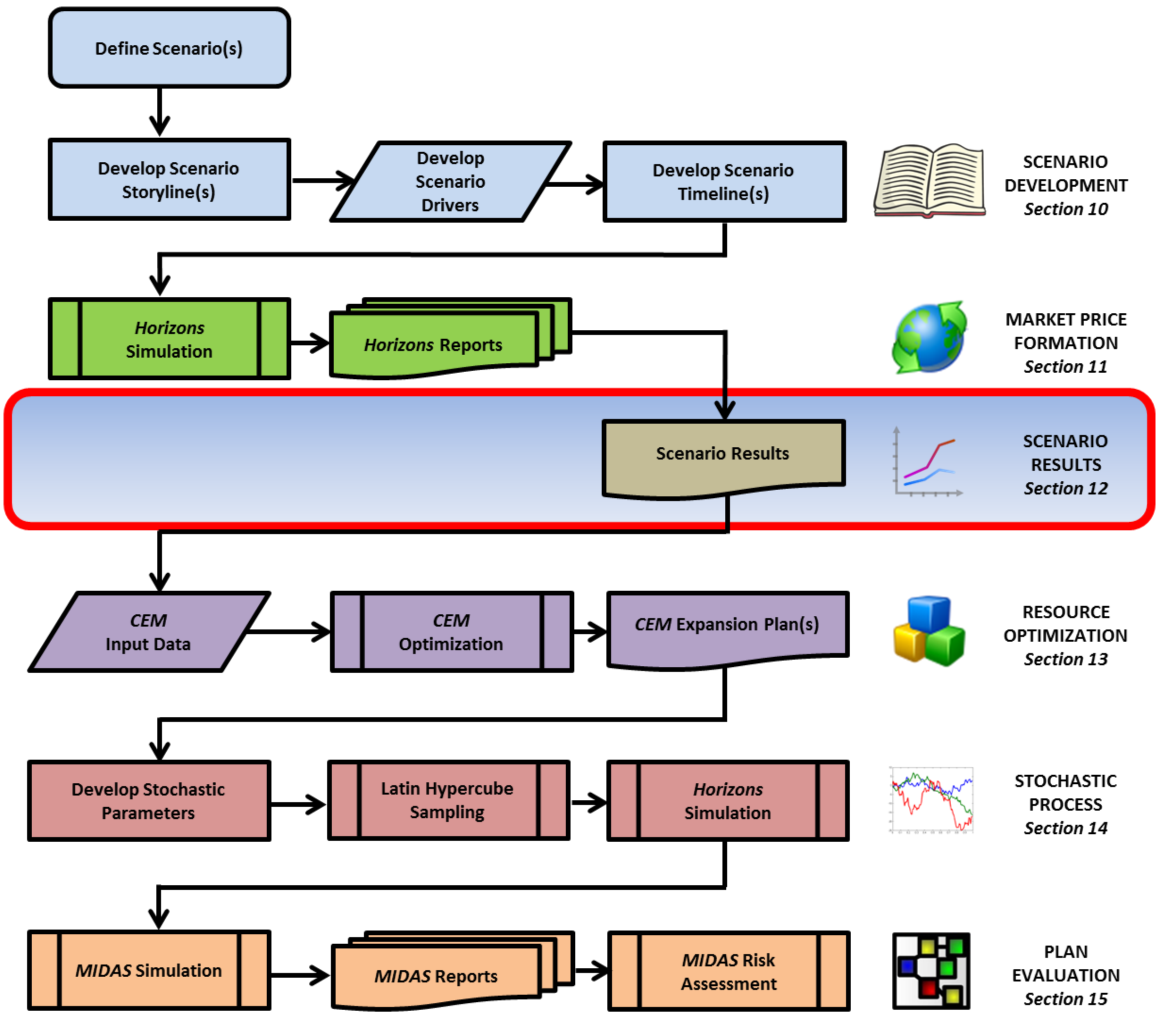


Source: NREL/EnerNex

12 SCENARIO RESULTS

The Horizons Interactive Market Model simulation is repeated for each scenario providing unique attributes associated with each probable future. The market model results are then analyzed to ensure they provide reasonable "book-ends" that examine low probability but high consequence outcomes.

Figure 40 IRP Flowchart – Scenario Results



Scenario CO_2 Emission Trajectories

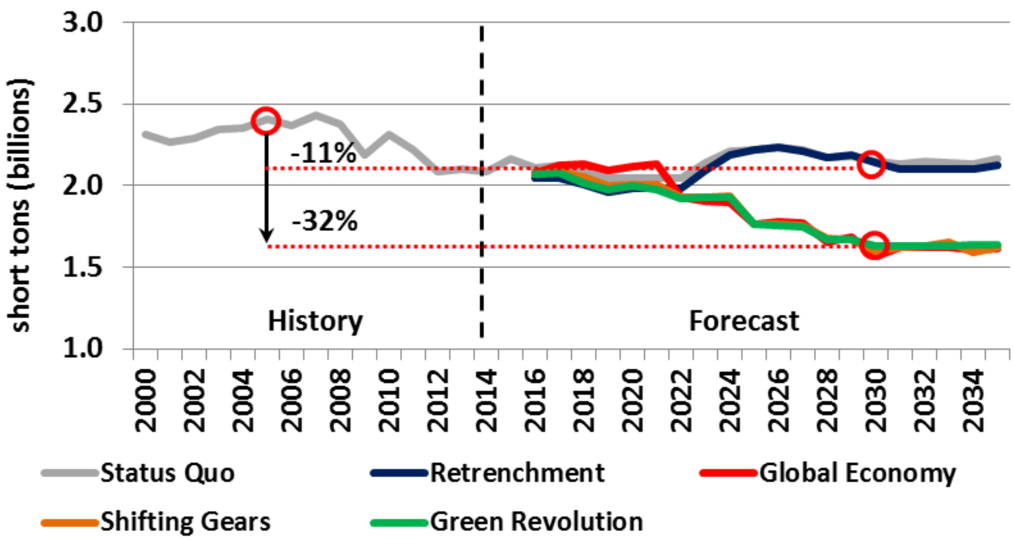
As illustrated in the graph below, in Status Quo and Retrenchment, U.S. CO_2 power sector emissions decrease 11% below 2005 levels by 2030. In Global Economy, Shifting Gears, and Green Revolution, U.S. CO_2 emissions decrease 32% below 2005 levels by 2030 in accordance with the final EPA CPP rule. The aforementioned scenarios achieve the 32% reduction target using different enforcement techniques.

- Global Economy implements a nation-wide *Cap and Trade* program, which conforms to the EPA's CPP mass-based approach. Existing steam-coal, steam-oil, and combined cycle units are allocated a proportionate share of their state's allowances. Under the assumptions in this scenario, the affected existing generating units plus new units would participate in the trading program.

- Shifting Gears employs a *Carbon Tax* on all power sector carbon emissions with the tax proceeds rebated to residential electricity consumers.

- Green Revolution implements an *Electric Generating Unit (EGU) Rate Cap* in which individual units must meet rate caps set by the EPA with affected power plants able to meet their emission standards via ERCs. New renewables are able to produce ERCs. This approach conforms to the EPA rate-based approach.

Figure 41 Scenario U.S. Power Sector CO_2 Emission Trajectories

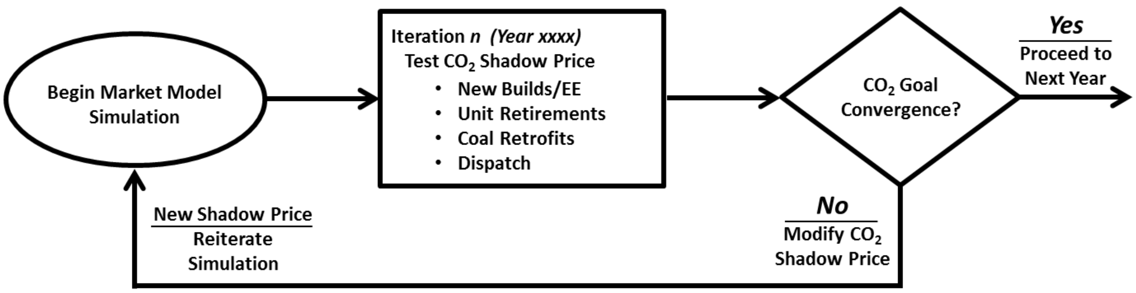


Source: IMPA

Scenario CO_2 Shadow Price

To determine the value of carbon in the absence of an actual carbon market, IMPA calculates a shadow price of carbon under the market and regulatory conditions of each scenario. Shadow pricing is method of investment or decision analysis that applies a hypothetical surcharge to a given commodity which in turn affects generation additions, energy efficiency, retirements, retrofits, and ultimately the market model dispatch. By entering an annual CO_2 emission goal, the model will iterate with modified shadow prices until the annual CO_2 goal is achieved. The convergent shadow price is the value of CO_2. This process is shown in the flowchart below.

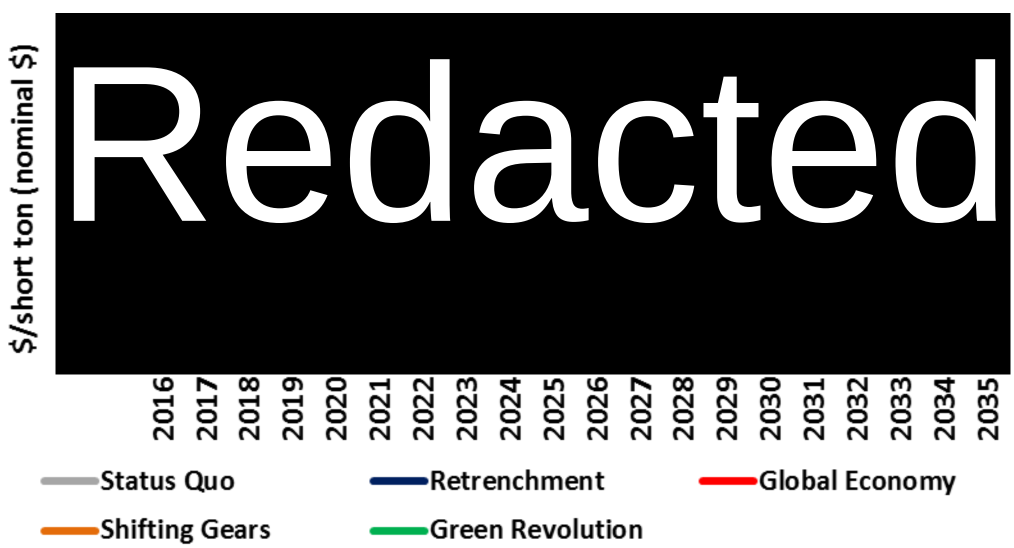
Figure 42 CO_2 Shadow Price Flowchart



In Status Quo, which does not have to meet the EPA's CPP requirements, the only U.S. carbon market is RGGI and CA AB32. In Retrenchment, which also does not have to meet the EPA's CPP requirements, there are no U.S. carbon markets as they are all repealed.

Global Economy, Shifting Gears, and Green Revolution all have some type of carbon value although the value is derived from three different valuation structures. Global Economy uses an interstate cap and trade valuation. Shifting Gears uses a carbon tax. And Green Revolution uses ERCs.

Figure 43 Scenario CO_2 Value

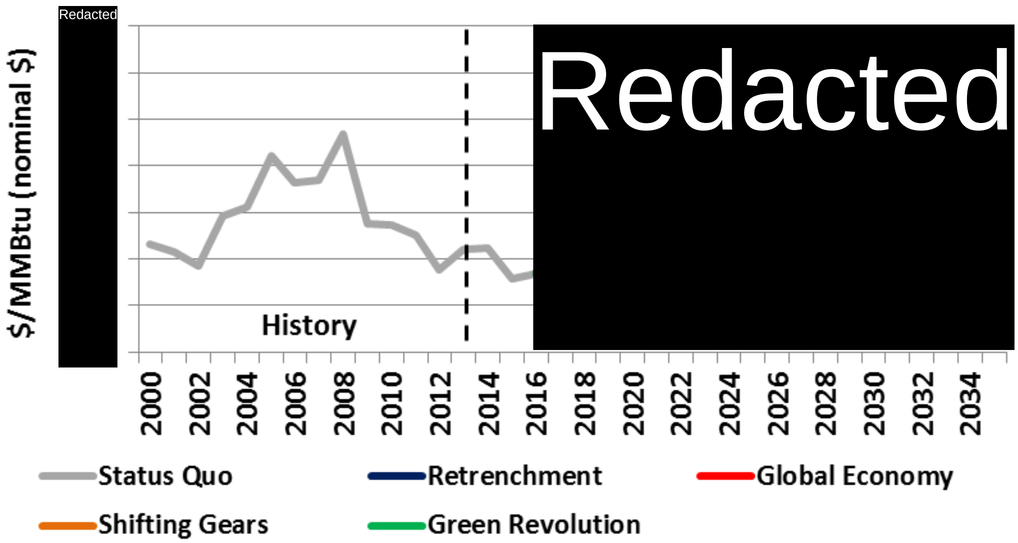


Source: IMPA

Scenario Natural Gas Prices

The Retrenchment scenario assumes high technically recoverable reserves, which allow for more wells per square mile, as well as a high estimated ultimate recovery rate. In contrast, the Green Revolution scenario assumes more stringent regulations are imposed on the natural gas industry, increasing the cost of production.

Figure 44 Scenario Natural Gas Prices

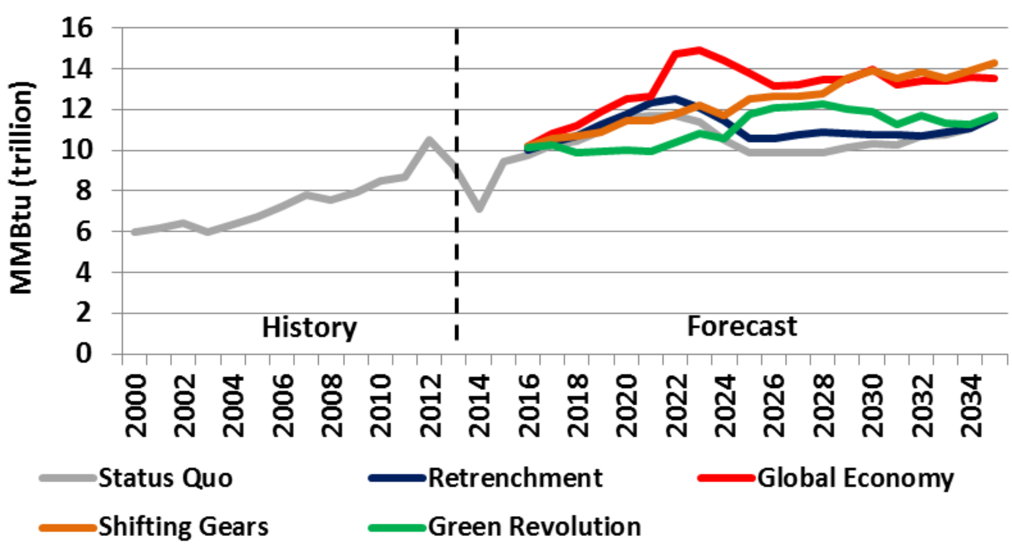


Source: IMPA

Scenario Natural Gas Burn

The Global Economy and Shifting Gears scenarios have the highest natural gas burn as more combined cycles are utilized.

Figure 45 Scenario Natural Gas Burn

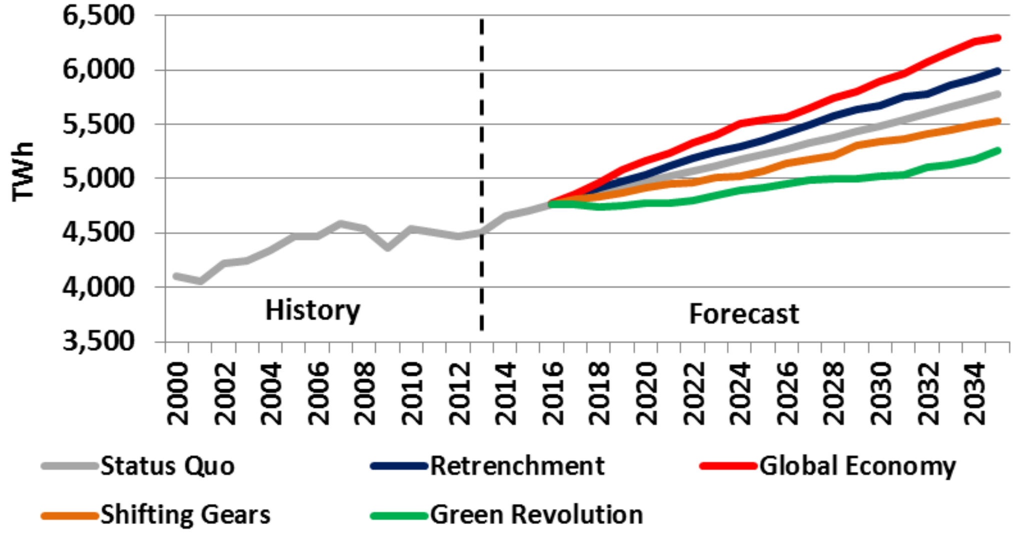


Source: IMPA

Scenario Load Forecast

The load growth is highest in Global Economy as the economy rebounds in this scenario. Green Revolution has the lowest load growth due to load destruction from distributed generation and increased federal energy efficiency standards.

Figure 46 Scenario Load Forecast (Energy)

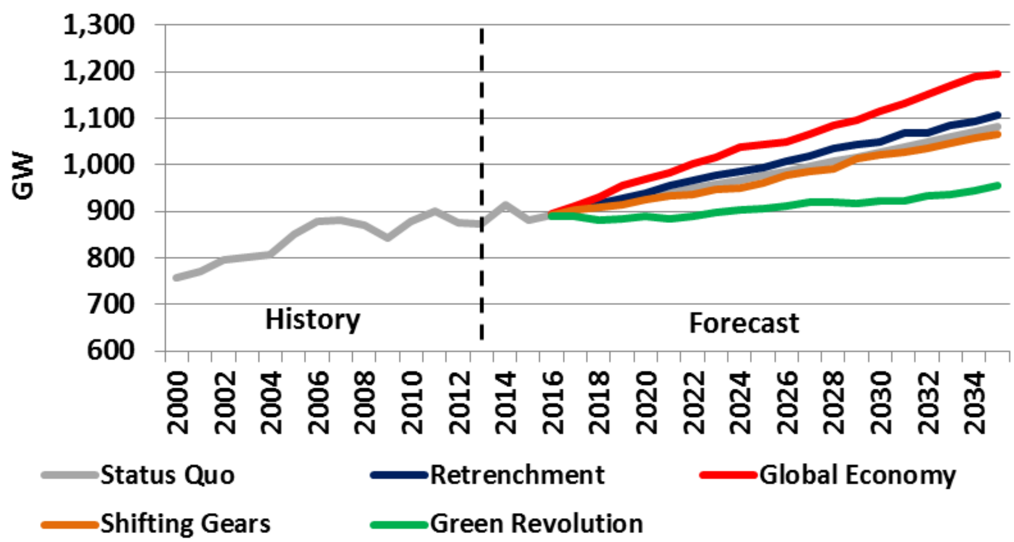


Source: IMPA

Scenario Peak Forecast

The demand growth is highest in Global Economy as the economy rebounds in this scenario. Green Revolution has the low demand growth due to distributed generation, increased federal energy efficiency standards, and peak demand shifting.

Figure 47 Scenario Load Forecast (Peak)

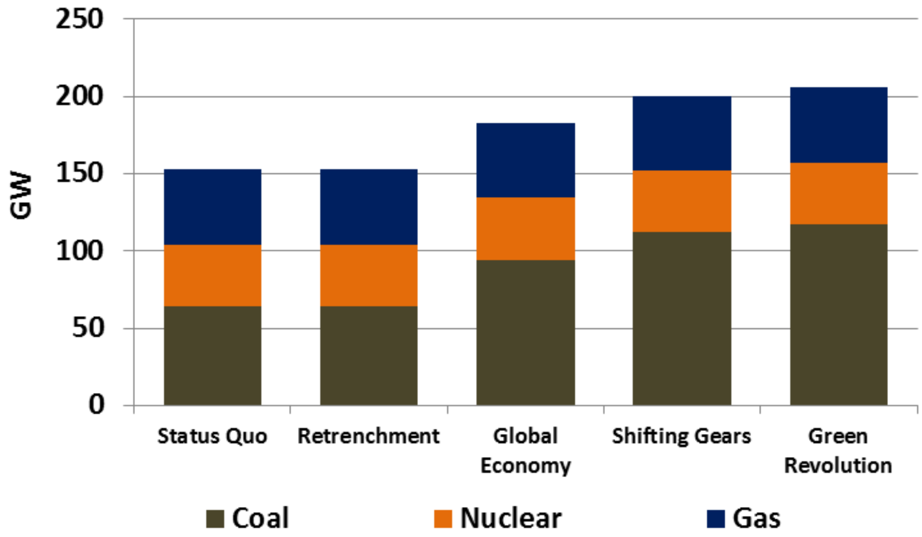


Source: IMPA

Scenario Capacity Retirements

Green Revolution, Shifting Gears, and Global Economy retire 117 GW, 112 GW, and 94 GW of the coal fleet by 2035, respectively. Status Quo and Retrenchment experience coal retirements due to age. 40 GW of nuclear is retired in all five scenarios.

Figure 48 Scenario Capacity Retirements

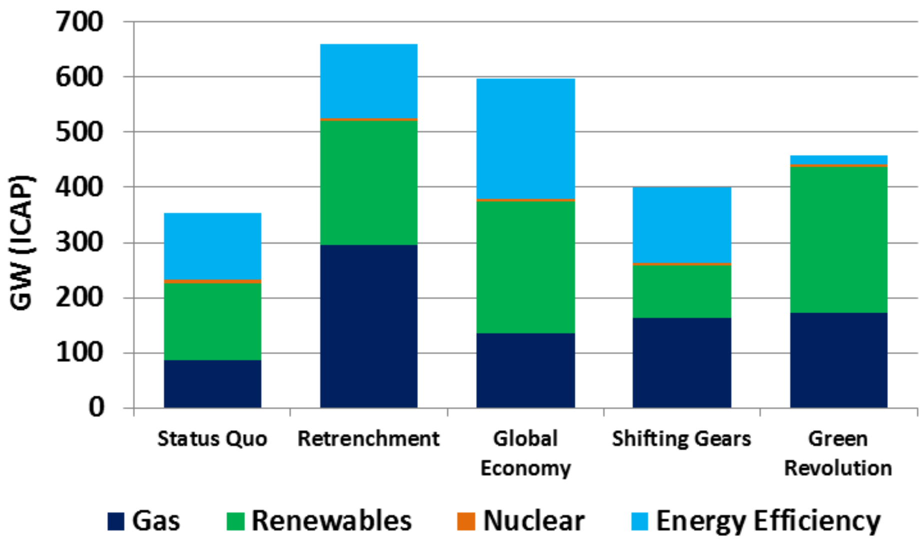


Source: IMPA

Scenario Capacity Additions

Global Economy adds the most wind and energy efficiency to meet the EPA's CPP while Shifting Gears complies with relatively even amounts of gas, renewables and EE. Green Revolution relies heavily on gas and renewables to comply with the rate based methodology. Utility sponsored EE is lower in Green Revolution as this case involves extensive government standards to reduce consumption. New nuclear was not found to be economic in any of the scenarios.

Figure 49 Scenario Capacity Additions

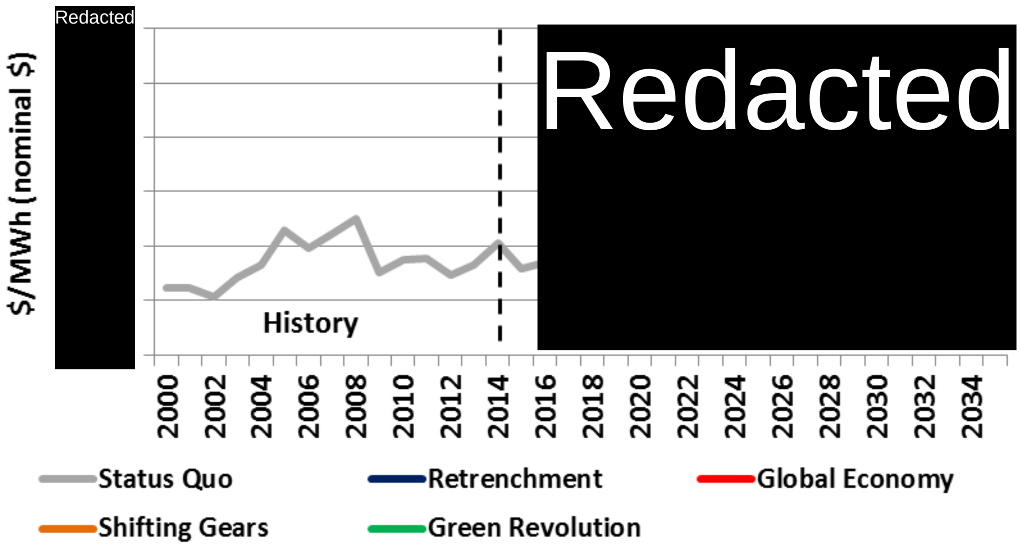


Source: IMPA

Scenario Electric Wholesale Prices

Annual wholesale prices are projected to be Redacted in Shifting Gears and Redacted in Green Revolution compared to the Retrenchment scenario. The effect of the carbon cap and trade on the Global Economy scenario is evident by the jump in wholesale prices beginning in 2022.

Figure 50 Scenario Market Prices

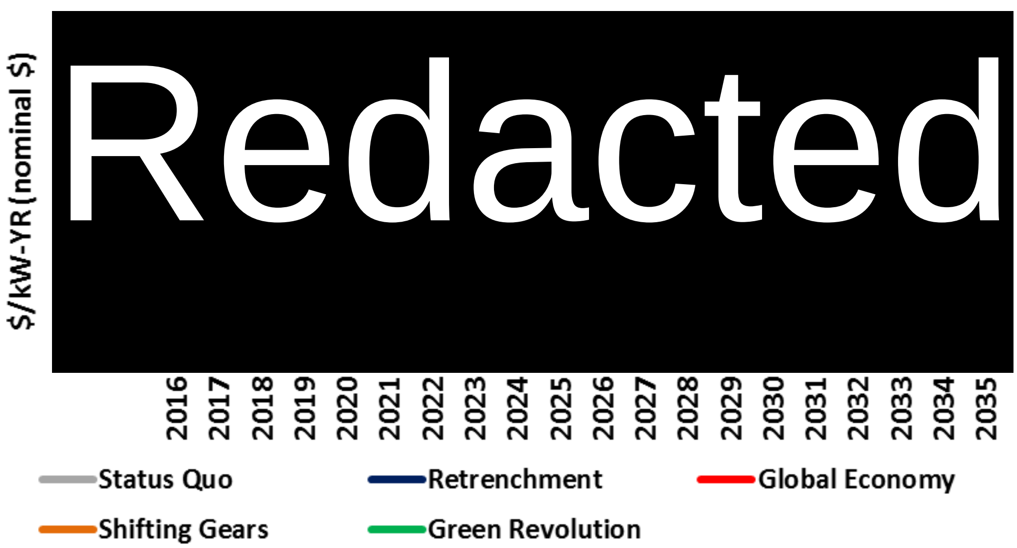


Source: IMPA

Scenario Capacity Prices

The weighted average capacity price for the MISO–IN (LRZ6) and PJM-RTO zones are shown in the graph below. The purpose of the IMPA capacity market forecast is to provide the direction and magnitude of capacity prices, but the outcome in specific years is subject to great uncertainty due to the timing of retirements, additions, participant bid behavior and regulatory uncertainty.

Figure 51 Scenario Capacity Prices



Source: IMPA

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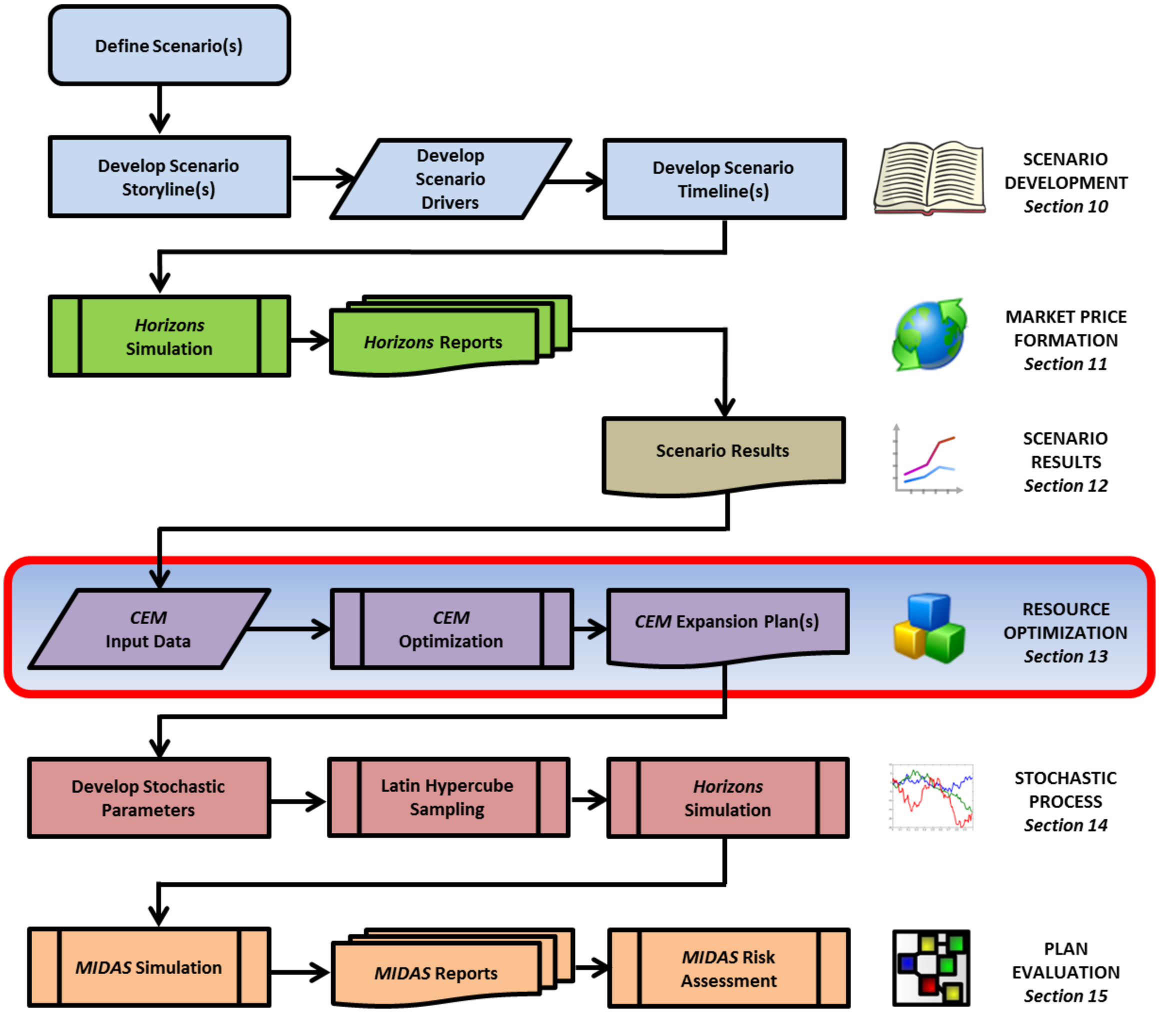
13 RESOURCE OPTIMIZATION

The defined scenarios and their market attributes are incorporated with IMPA's portfolio in the Capacity Expansion Module (CEM). This module performs an optimization of the sizing and timing of supply-side and demand-side resource alternatives for each scenario. The end result is an optimal plan developed for each scenario.

Figure 52 IRP Flowchart – Resource Optimization

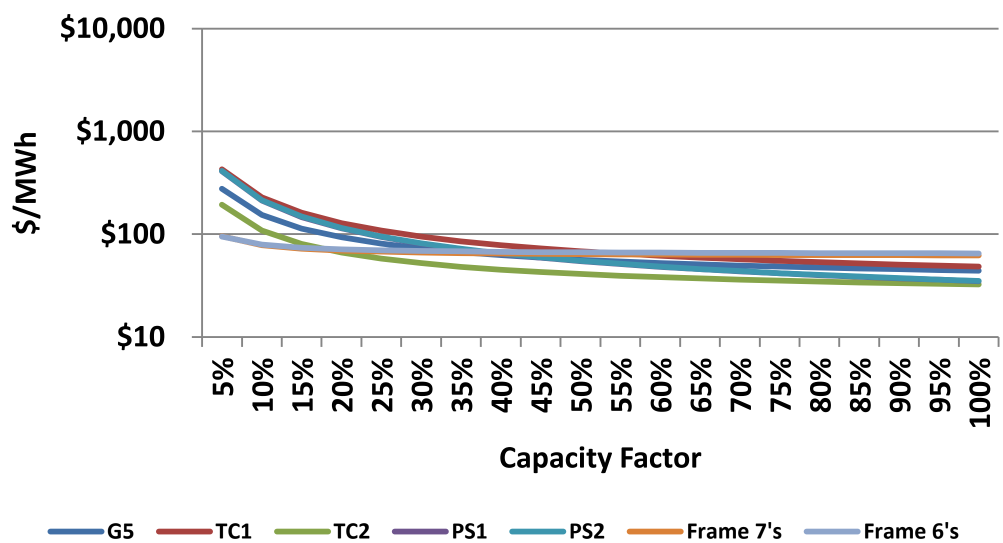


13.1 NEW SUPPLY-SIDE OPTIONS

Existing Supply-Side Resources

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. This is performed by allowing the expansion model to opt to retire an existing resource and replace it with other alternatives. When a unit is retired in this manner, all future capital expenditures, O&M and fuel costs are removed, however, all remaining bond obligations associated with the facility remain. A relative comparison of the incremental capital and operating costs of IMPA's existing resources at various load factors is shown below. See Appendix E for detailed existing unit data.

Figure 53 Retirement Screening Curve



Source: IMPA

New Supply-Side Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. For example, IMPA does not screen various brands and models of CTs against each other to determine the generic CT for use in the IRP expansion. CT pricing is sufficiently compressed that one CT brand over another will not cause the expansion model to select a CT when a CT is not needed or vice versa. The selection of the actual brand and model to construct would be determined in the bid and project development process.

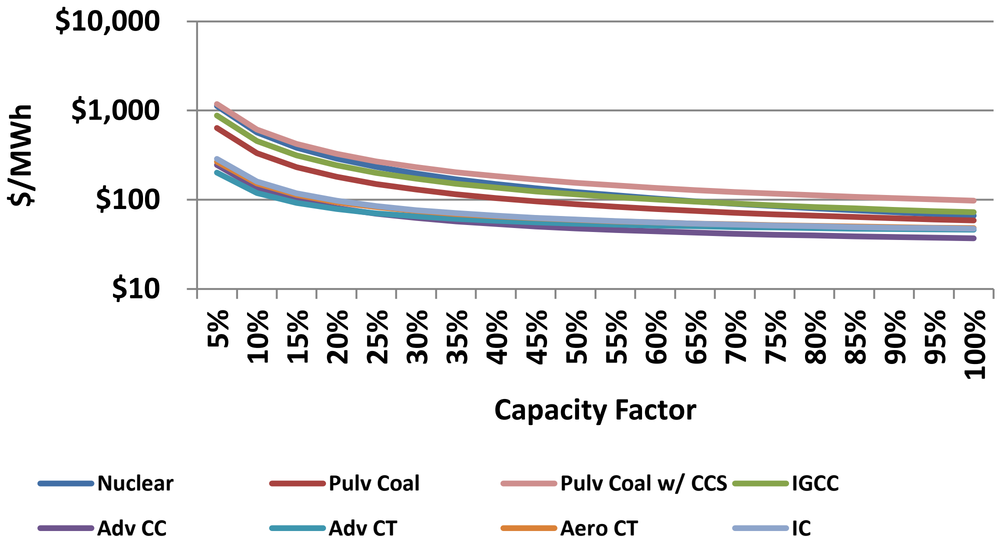
The traditional generating resources considered in this study include:

- Nuclear (100 MW from a 1100 MW unit)
- Coal-fired steam generation (100 MW from a 1300 MW unit)
    - with or without CCS depending on the scenario
- Integrated Gasification Combined Cycle (IGCC) (100 MW from a 620 MW unit)
- Advanced combined cycle (CC) units (100 MW from a 450 MW unit)
- Advanced gas-fired combustion turbines (CT) (185 MW)
- Aero-derivative combustion turbine (100 MW)
- Gas-fired high efficiency internal combustion (IC) units (10 MW units in multi-unit sets of 50 MW)

Capital costs, operating costs and operating characteristics for the thermal resources were taken from the U.S. Energy Information Administration (EIA) *Annual Energy Outlook 2014 & 2015*. See Appendix F for detailed expansion unit data.

A comparison of expansion alternatives at various load factors is shown below.

Figure 54 Thermal Screening Curve



Source: IMPA

New Renewable Resources

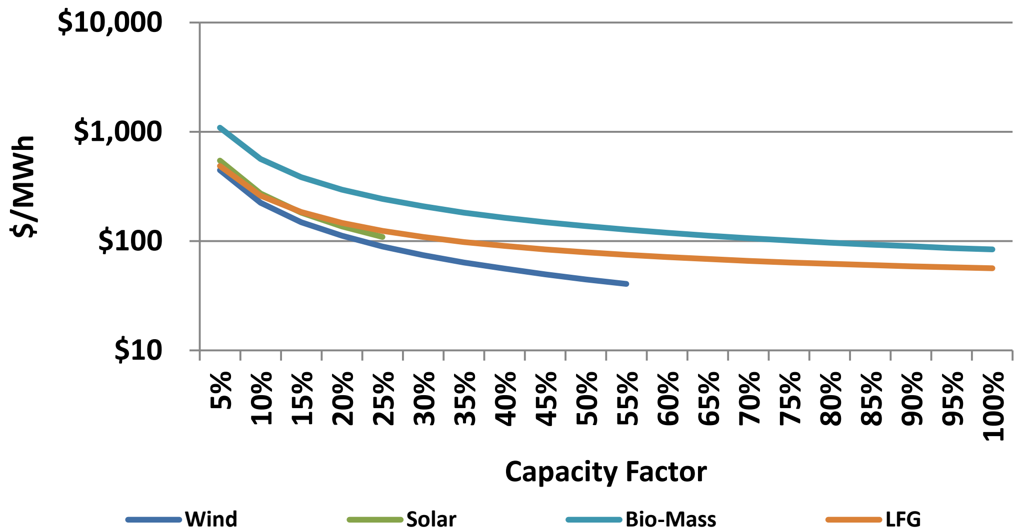
In addition to the traditional resources discussed above, the expansion model was allowed to pick from a variety of renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Wind
- PV Solar
- Bio Mass (25 MW)
- LFG (2.5 MW units in sets of 10 MW)

Capital costs, operating costs and operating characteristics for renewable resources were taken from the U.S. Energy Information Administration (EIA) *Annual Energy Outlook 2014* and from the U.S. Department of Energy (DOE) *Wind Vison: A New Era for Wind Power in the United States* report as well as IMPA experience in solar park construction and operation. See Appendix F for detailed expansion unit data.

A comparison of renewable alternatives at various load factors is shown below.

Figure 55 Renewable Screening Curve



Source: IMPA

Retail Customer-Owned Generation

As stated previously, other than emergency generators, IMPA has very little customer owned generation connected to its member systems. There are approximately 15 net metering installations, all less than 10 kW.

IMPA does not currently have any customers on the system that operate a CHP system. Since a CHP or customer owned generation system is a very site specific resource that is totally dependent on having a heating load customer, IMPA did not model an expansion unit to represent these systems. Going forward, IMPA will work with its members and their customers to investigate the addition of CHP or renewable systems at customer locations when proper conditions arise.

13.2 New Demand-Side Options

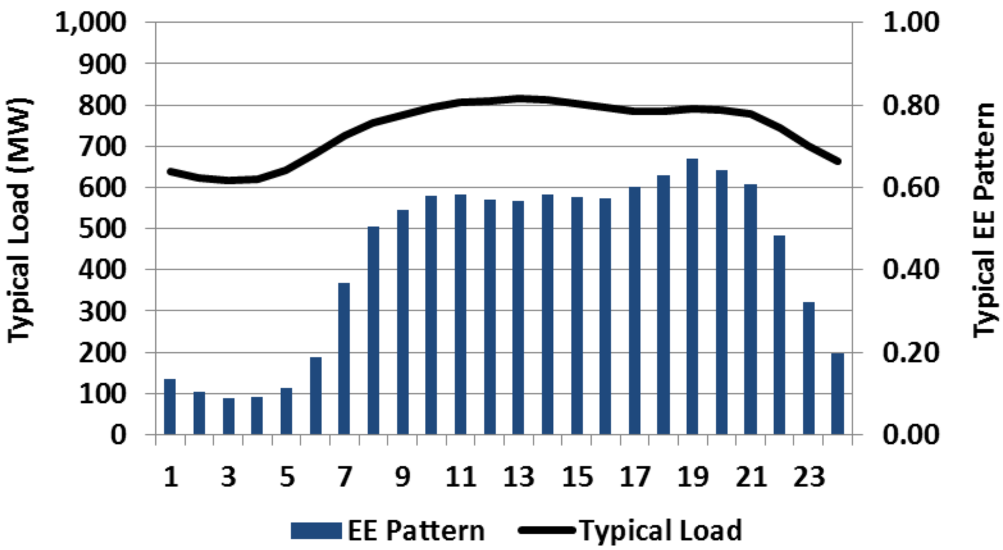
To model energy efficiency and demand response, the CEM model considered the sizing and timing of demand-side resources in the same fashion as the model considered supply-side resources. This involves modeling the characteristics of the demand-side resources to look like a generating unit so they are placed on equal footing. Utilizing IMPA's past experience with energy efficiency programs, the cost characteristics, hourly patterns, load factors, and coincidence factors were modeled.

13.2.1 Energy Efficiency Savings Characteristics

A critical step in modeling energy efficiency is to develop hourly energy efficiency patterns. The hourly patterns vary by type-of-measure, time-of-day, day-of-week, and month. For example, a measure that replaces inefficient lighting in a school gymnasium provides benefits during the school year when the gymnasium is in use, but provides little benefit during the summer when school is not in session. Measures such as residential HVAC provide a summer peak clipping benefit, but no benefit in the winter.

The hourly patterns of the various measures are aggregated into a single 8,760 hourly "per unit" pattern. Shown below is an annual "typical representation" of the aggregate per unit energy efficiency pattern superimposed on IMPA's average annual load.

Figure 56 Energy Efficiency Hourly Pattern



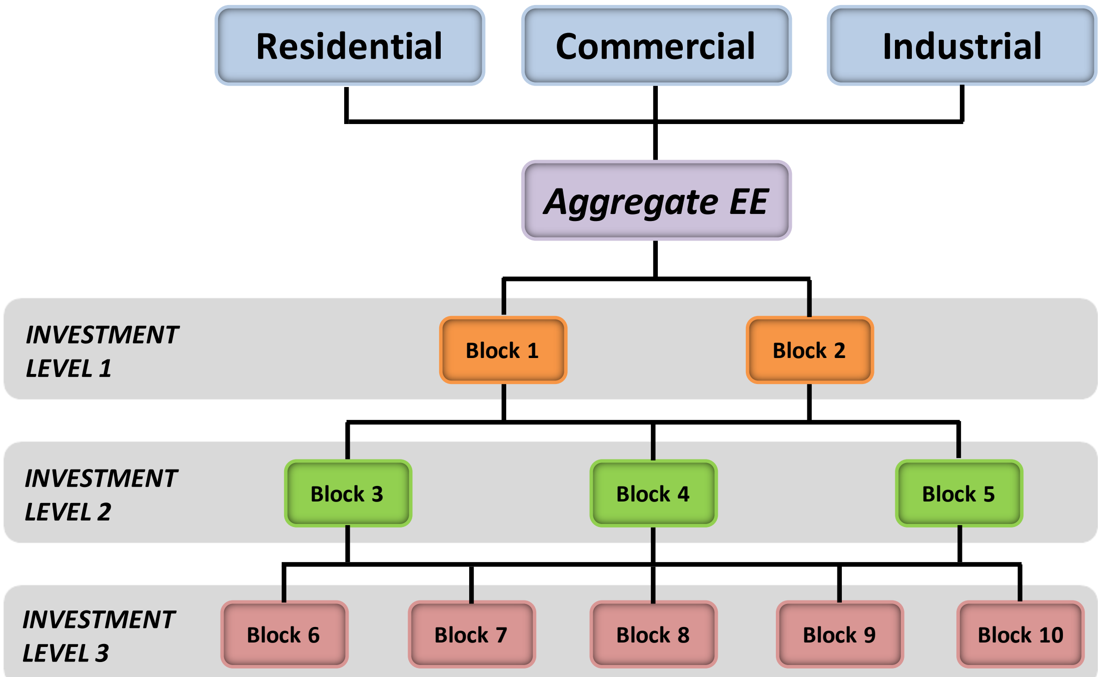
Source: IMPA

The annual load factor of the EE pattern is 43% which exhibits similar time-of-day characteristics as one would expect from a combined cycle unit. One distinction between a combined cycle and energy efficiency is the availability during the peak. As a dispatchable resource, a combined cycle unit is available upon request to serve the peak demand subject to forced outages (≈6%). However, as a non-dispatchable resource, energy efficiency's contribution to peak reduction is based on its coincidence factor during the peak hour. The aggregate coincidence factor of the IMPA EE pattern is 52.3% as measures such as residential lighting, street lighting, and even some C&I measures aren't coincident with the peak demand hour.

13.2.2 Energy Efficiency Investment Characteristics

It is well understood that some energy efficiency measures are more cost effective and easier to implement than others. It is also recognized that there is a finite amount of less expensive EE that can be obtained in any one year after which the next set of measures become more expensive. To address this issue, IMPA developed an *Energy Efficiency Investment Hierarchy*.

Figure 57 Energy Efficiency Investment Hierarchy

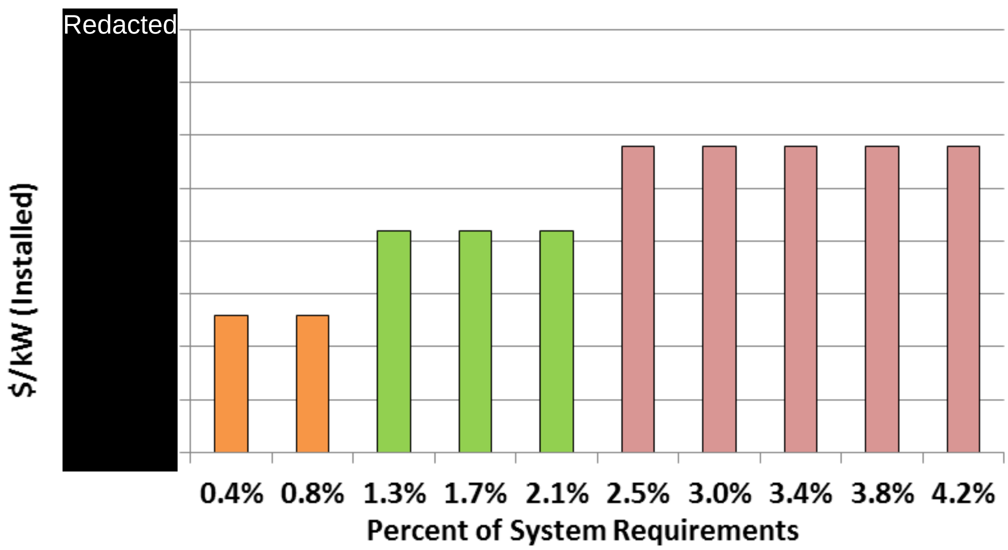


Source: IMPA

As described earlier, an Aggregate EE hourly pattern is created from a variety of residential, commercial, and industrial measures. The Aggregate EE represents the types of energy efficiency measures we know and serves as a proxy for new measures which will undoubtedly be developed in the future.

The Aggregate EE is broken into three (3) investment levels which are progressively more expensive. The three investment levels contain ten (10) blocks. Each block is equivalent to 0.42% of IMPA's load. If all ten blocks were chosen, that would add 4.2% of energy efficiency in that year. The first investment level contains two (2) blocks. The second investment level contains three (3) blocks. And the third investment level contains five (5) blocks. IMPA felt it was important to make available large amounts of energy efficiency, albeit at a higher price, to provide a DSM choice in carbon scenarios where avoided costs could be very high. A fixed component ($/kW-Yr) was added to each block to account for indirect expenses such as administration, marketing, and evaluation, measurement and verification (EM&V).

Figure 58 Energy Efficiency Investment Levels



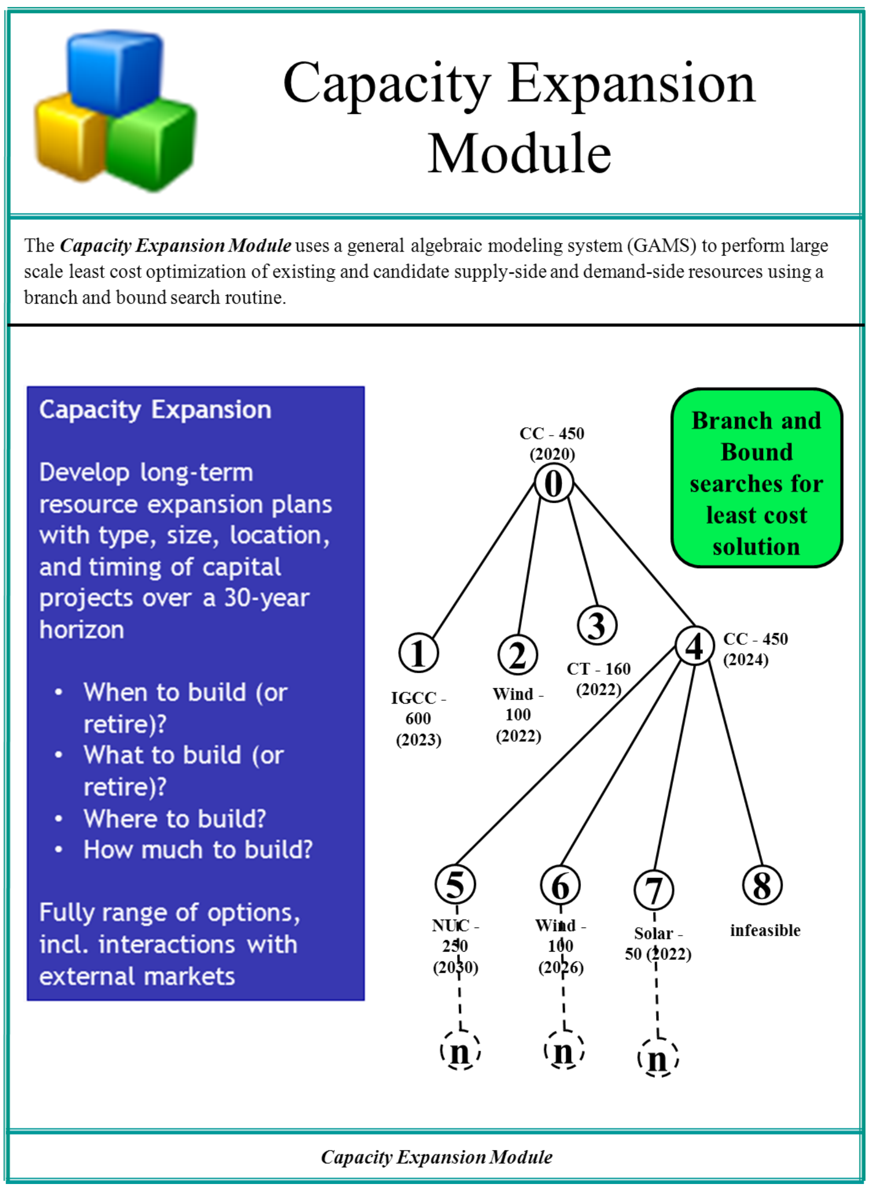
Source: IMPA

13.3 Capacity Expansion Module

Utilities create an IRP to provide a framework for prudent future actions required to ensure continued reliable and least cost electric service to their customers. An important part of this exercise is to evaluate the future resource needs to meet growing demand, and present a balanced and responsible resource strategy to the stakeholders and the state regulatory bodies that meets system reliability requirements, is fiscally sound, promotes environmental stewardship, and balances risks and costs.

The Capacity Expansion Module (CEM) is a long-term portfolio optimization model for automated screening and evaluation of decisions for supply-side capacity expansion and retirement options, contract transactions, and demand-side management programs.

Figure 59 Capacity Expansion Module Cut Sheet



Source: Ventyx

Capacity Expansion Module – Objective Function

The optimal resource expansion strategy is based on an objective function subject to a set of constraints. The goal of the CEM is to minimize the net present value cost of supply-side and demand-side projects, contract and spot market transactions, and generating station decommissioning costs subject to load balance, reliability, and investment constraints. Thus, the criterion for evaluation is minimization of the net present value of revenue requirements (PVRR).

The CEM answers the key investment decisions of:

- What to build (or retire)?
- When to build (or retire)?
- Where to build?
- How much to build?

The CEM is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads in each area with load obligations. The model includes all existing and proposed plants in a utility system. Binary integer variables are used in the MILP to represent discrete decisions regarding whether to build or retire generation or enter into a particular contract transaction. General integer variables are used to represent how many discrete units of generation to add.

The CEM solves for the "optimal" resource plan, considering the cost effectiveness of the specific resource options, including their scale and timing to meet a target reserve margin. Decisions on generation additions or retirements are made on an annual basis. Decisions on contract transactions and demand-side management programs are made once for each potential contract's delivery period.

Capacity Expansion Module – Simulation Time

Capacity expansion planning models have very long time horizons (typically 20+ years). To remain practical in computer memory requirements and execution speed, time is represented in buckets rather than individual hours. The CEM uses the "representative hours" approach, in which average generation and load values in each representative time of use period in a week are scaled up appropriately to span all hours of the week and days of the month. IMPA utilizes powerful desktop PC workstations with 12 GB of RAM, 64-bit operating system, and a 3.2 GHz clock speed to run the CEM simulations.

Despite the considerable advantages of using the CEM for resource capacity planning, it is only intended for use as a preliminary screening tool for quickly and objectively narrowing the choice set from an extremely large number of possible resource plans down to a few "good" alternatives for more detailed production, rate, and financial simulation analysis using the MIDAS Gold module.

13.4 Selected Resource Expansion Plans

IMPA ran the five scenarios discussed above in the CEM module to develop five different expansion plans. The resulting plans are shown in the table below. IMPA's next significant resource need is in 2021 when a 100 MW capacity and energy contract expires. Coincidently, the start date of the EPA's CPP is in 2022. So it is within the 2021-2022 timeframe where IMPA's next resource decision lies.

Table 12 Expansion Results – 5 Plans

Drivers	Plan01	Plan02	Plan03	Plan04	Plan05
Economic Growth	Reference	Med-High	High	Med-Low	Low
Capital Construction Cost	Reference	Low	Med-Low	Med-High	High
Load Forecast	Reference	Med-High	High	Med-Low	Low
Load Factor	Existing	1.5% Higher	1.5% Lower	3% Lower	3% Higher
Natural Gas Prices	Reference	Low	Med-Low	Med-High	High
Coal Price	Reference	Low	Med-High	Med-Low	High
CO_2 Policy	Existing	No Policy	Mass-Based	CO_2 Tax	Rate-Based
Reserve Margin	Pool + 1%	Pool + 2%	Pool Req	Pool + 2%	Pool + 3%
2016	10 S	10 S	10 S	10 S	10 S
2017	10 S	10 S	10 S	10 S	10 S
2018	10 S	10 S	10 S, 10 EE	10 S	10 S, 39 EE
2019	10 S	10 S	10 S, 20 EE	10 S	10 S, 39 EE
2020	10 S	10 S	10 S, 31 EE	10 S	10 S, 54 EE
2021	200 CC	200 CC	200 CC, 29 EE	100 CC, 12 W 4 EE	54 EE
2022	Retire WWVS 100 CC		Retire WWVS/G5/TC1 300 CC, 39 EE	41 W, 24 EE	Retire G5/WWVS 185 CT, 150 W
2023			44 EE	42 W, 24 EE	
2024			38 EE	41 W, 39 EE	
2025			38 EE	Retire G5, 185 CT 42 W, 35 EE	Retire TC1, 49 W
2026			23 EE	2 W, 23 EE	
2027			6 EE	23 EE	
2028				21 EE	125 W
2029			3 EE	3 W, 15 EE	
2030			8 EE	10 EE	40 W
2031			8 EE		
2032			8 EE	1 W	2 W
2033			8 EE		
2034	200 CC	200 CC	200 CC, 8 EE	185 CT, 1 W	200 CC, 2 W
2035			8 EE		4 W
Retirements – MW	(90)	0	(312)	(156)	(312)
Natural Gas Additions – MW	500	400	700	470	385
Renewables – MW	50	50	50	235	427
Energy Efficiency – MW	0	0	329	218	186

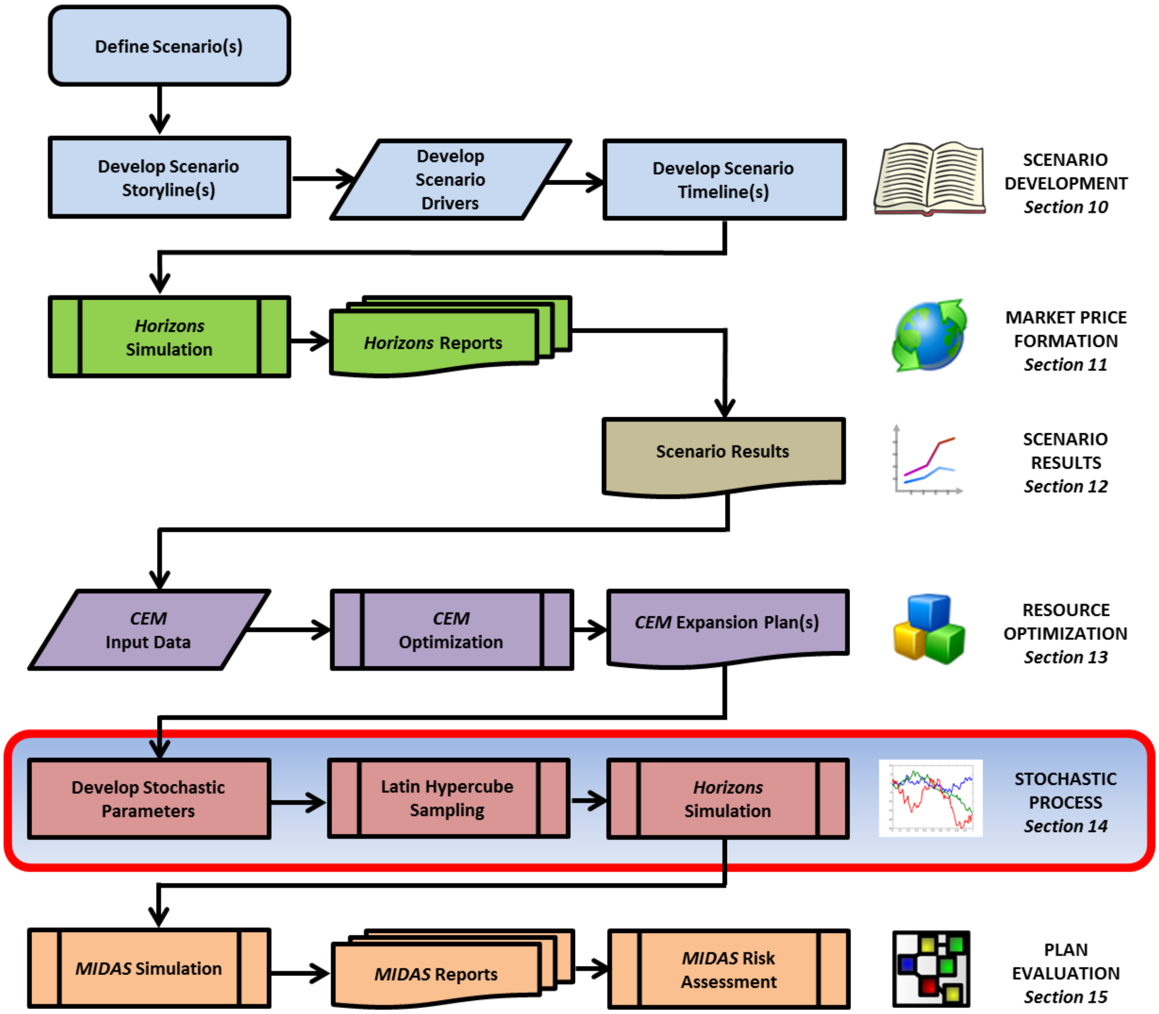
CC = Advanced Combined Cycle
CT = Advanced Combustion Turbine
W = Wind
S = Solar
E = Energy Efficiency

G5 = Gibson 5
TC1 = Trimble County 1
WWVS = Whitewater Valley Station

14 STOCHASTIC PROCESS

Prior to the detailed analysis of each plan, a set of sensitivities is developed which will allow IMPA to consider the impact of uncertainty for each plan. The Stochastic Process is a combination of Latin Hypercube sampling coupled with Horizons Interactive market model simulations.

Figure 60 IRP Flowchart – Stochastic Process



Horizons Interactive is an integrated market model, which uses a structural approach for forecasting prices that captures the uncertainties (sensitivities) in regional electric demand, resources and transmission, and provides a solid basis for decision-making. Using a stratified Monte Carlo sampling program, which is referred to as the Latin Hypercube, Horizons Interactive generates regional forward price curves across multiple stochastic futures (draws). The draws are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, unit availability, hydro output, capital expansion cost, transmission availability, reserve margin, emission price, weather, etc.) and take into account statistical distributions, correlations, and volatilities.

Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range.

Prices are derived using a rigorous probabilistic approach that performs the following tasks:

- Quantifies the uncertainties that drive market price through a stratified Monte Carlo sampling model (Latin Hypercube);
- Puts the uncertainties into a decision tree;
- Evaluates multi-region, hourly market price for a set of consistently derived futures using Horizons Interactive; and
- Accumulates the information into expected forward price and volatility of the marketplace.

The uncertainty drivers were developed for the IMPA specific zones of interest (MISO-Indiana, MISO-Iowa, MISO-Illinois, PJM-AEP, and PJM-DEOK) as well as all of the other zones in the Horizons Interactive market model.

Uncertainty Variables

For the price trajectories, IMPA examined the impact of load, fuel price, emissions, and supply on regional spot market energy and capacity prices. Specifically, the following uncertainties were evaluated:

Demand
- Long-Term Electricity Demand Growth
- Mid-Term Peak Demand
- Mid-Term Energy
- Reference Load Shape Year

Fuel Prices
- Long-Term Gas Price
- Long-Term Coal Price
- Long-Term Oil Price
- Mid-Term Gas Price

Emissions
- Long-Term CO_2 Price *(Calculated Shadow Price)*

Supply
- Long-Term Capital Costs
- Mid-Term Coal Unit Availability

- Fuel Supply Disruption *(Polar Vortex)*

Congestion

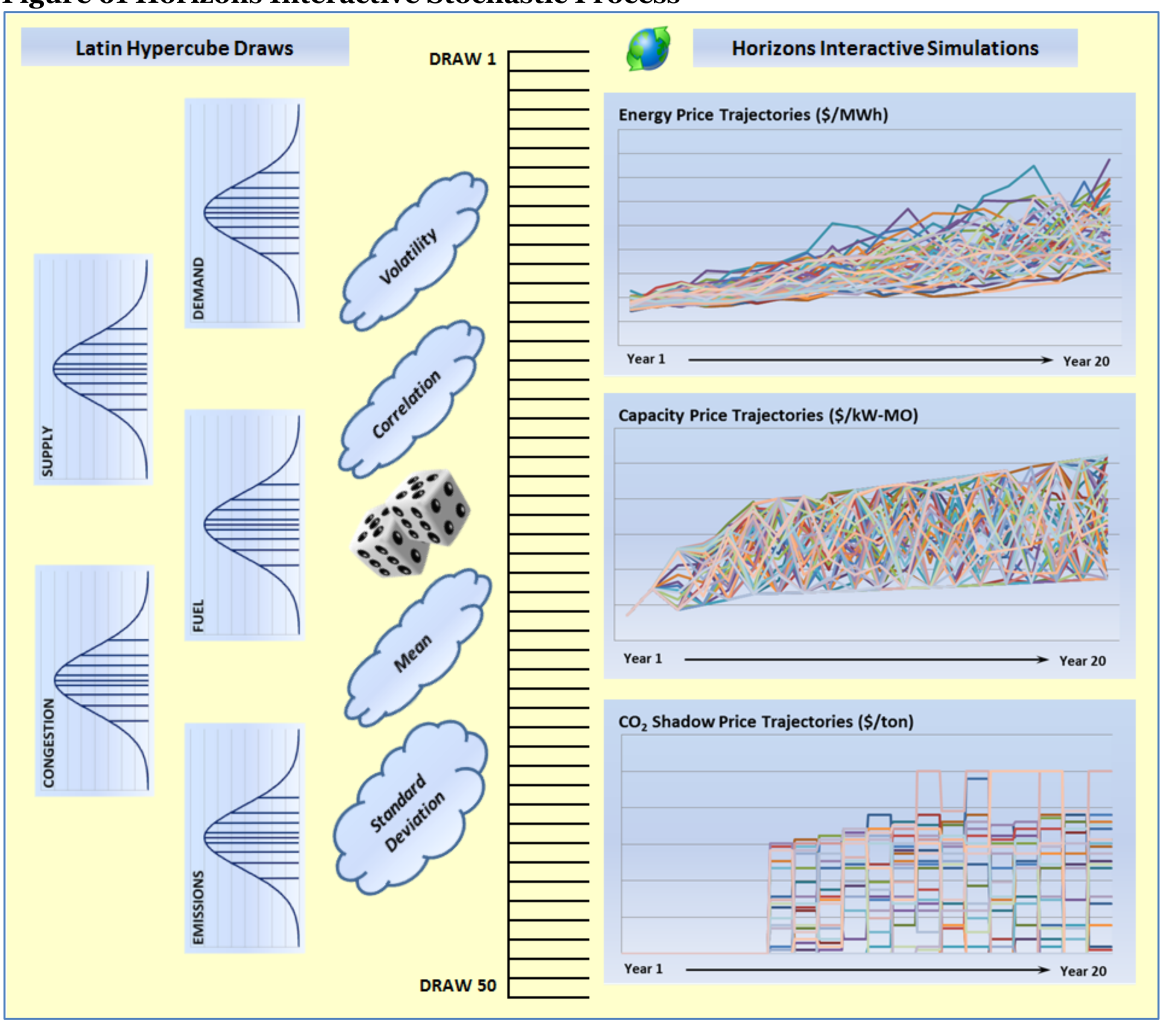
- Mid-Term Congestion

Horizons Interactive – Stochastic Simulation Time

For its stochastic process, IMPA creates 50 stochastic futures. Fifty trajectories strike a balance between the number of stochastic futures required for a comprehensive solution and a manageable number of simulations.

IMPA's technique for creating stochastic market prices is very resource intensive because the hourly zonal market price for each future is computer simulated, not mathematically estimated. While the Horizons Interactive market model is widely considered one of the fastest commercial software models for zonal market price simulation, the simulation time to create 50 stochastic futures including the CO_2 shadow prices as well as the nodal algebraic model (NAM) simulation for creating LMPs takes nearly 12 days using a desktop PC workstation with 12 GB of RAM, 64-bit operating system, and a 3.2 GHz clock speed.

Figure 61 Horizons Interactive Stochastic Process



Source: IMPA

14.1 Long-Term Uncertainties

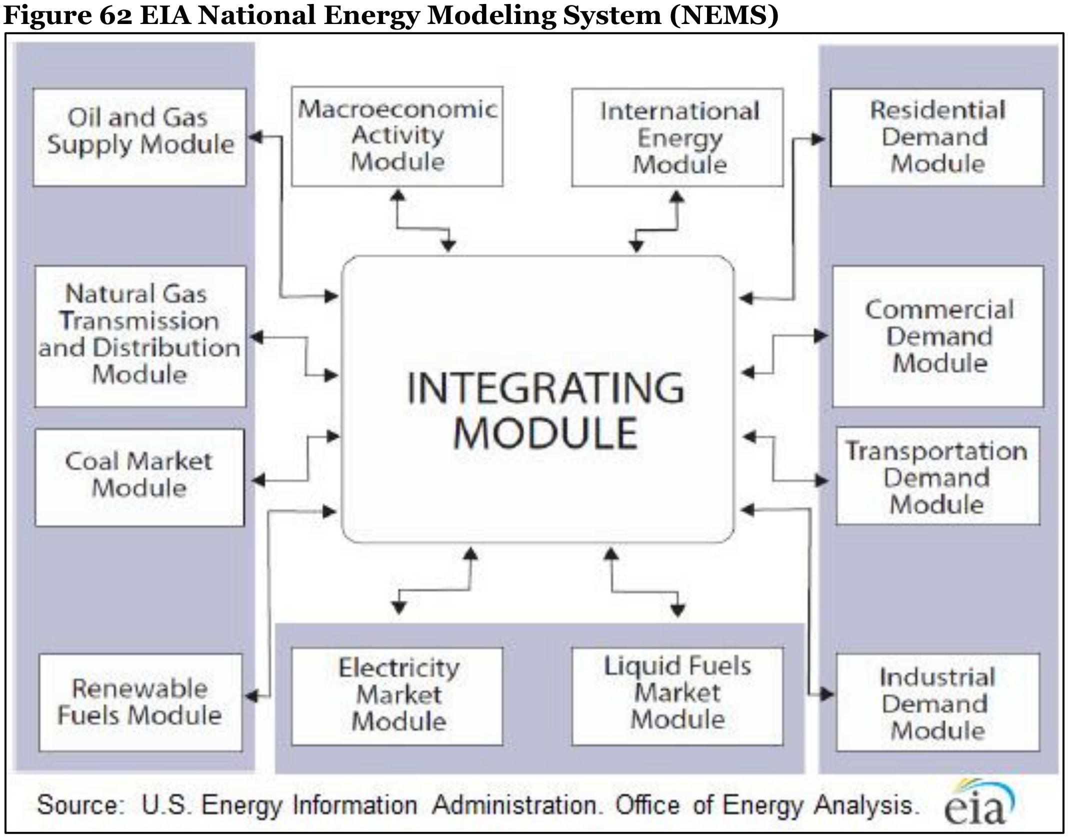
IMPA built its long-term stochastic draws based on the underlying projections of the *EIA Annual Energy Outlook 2014* (AEO2014). The U.S. Energy Information Administration (EIA) projections provide the key input drivers of electricity price such as fuel price and demand which supplement IMPA's proprietary assumptions and projections.

EIA Annual Energy Outlook 2014

The National Energy Modeling System Projections in the AEO2014 are generated using the National Energy Modeling System (NEMS), developed and maintained by the Office of Energy Analysis of the EIA. The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation (NERC) for electricity; and 8 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

NEMS is organized and implemented as a modular system shown in the figure below.

Figure 62 EIA National Energy Modeling System (NEMS)



Source: EIA

The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users.

The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors for each year. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence. Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

EIA2014 Cases

Projections by the EIA are not statements of what will happen but of what might happen, given the assumptions for any particular case. To that end, the EIA developed a reference case (business as usual estimate) and 29 additional cases for Annual Energy Outlook 2014.

The 30 EIA cases are briefly described below.

Table 13 EIA Annual Energy Outlook 2014 – 30 Cases

Reference	Low VMT	High Coal Cost
Low Economic Growth	Accelerated Nuclear Retirements	2013 Demand Tech
High Economic Growth	Accelerated Coal Retirements	Best Demand Tech
Low Oil Price	Accelerated Nuclear and Coal Retirements	High Demand Tech
High Oil Price	Low Nuclear	Energy Savings and Industrial Competitiveness Act
No Sunset	High Nuclear	Low Electricity Demand
Extended Policies	Low Renewable Technology Cost	No GHG Concern
High Rail LNG	Low Oil and Gas Resource	GHG10
Low Rail LNG	High Oil and Gas Resource	GHG25
High VMT	Low Coal Cost	GHG10 and Low Gas Prices

Source: EIA

1. Reference: Business as usual (BAU). Real GDP grows at an average annual rate of 2.4% from 2012 to 2040. Crude oil prices rise to about $141/barrel (2012 dollars) in 2040.
2. Low Economic Growth: Real GDP grows at an average annual rate of 1.9% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case.
3. High Economic Growth: Real GDP grows at an average annual rate of 2.8% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case.
4. Low Oil Price: Low prices result from a combination of low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) increases its market share to 51%, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $70/ barrel in 2017 and rise slowly to $75/barrel in 2040.
5. High Oil Price: High prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. OPEC market share averages 37% throughout the projection. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $204/barrel (2012 dollars) in 2040.
6. No Sunset: Begins with the Reference case and assumes extension of all existing tax credits and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as Corporate Average Fuel Economy (CAFE) improvements and periodic updates of efficiency standards. Also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period.
7. Extended Policies: Begins with the No Sunset case but excludes extension of the ethanol and biofuel subsidies that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC for CHP and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases light-duty vehicle (LDV) and heavy-duty vehicle (HDV) fuel economy standards in the transportation sector.
8. High Rail LNG: Assumes a higher LNG locomotive penetration rate into motive stock such that 100% of locomotives are LNG capable by 2037.
9. Low Rail LNG: Assumes a lower LNG locomotive penetration rate into motive stock, at a 1.0 average annual turnover rate for dual-fuel engines that can use up to 80% LNG.
10. High vehicle miles traveled (VMT): Assumes higher licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver in 2012 is 3% higher than in the Reference case, increasing to 7% higher in 2027, and then declining to 3% above the Reference case in 2040.
11. Low VMT: Assumes lower licensing rates and travel demand for specific age and gender cohorts. VMT per licensed driver is 5% lower than in the Reference case for the full projection. Licensing rates stay constant at 2011 levels or decline from 2011 to 2040, specific to gender, age, and census division categories.
12. Accelerated Nuclear Retirements: Assumes that all nuclear plants are limited to a 60-year life, uprates are limited to the 0.7 GW that have been reported to EIA, and no new

additions beyond those planned in the Reference case. Nonfuel operating costs for existing nuclear plants are assumed to increase by 3% per year after 2013.

13. Accelerated Coal Retirements: Begins with the AEO2014 High Coal Cost case assumptions and also assumes that nonfuel operating costs for existing coal plants increase by 3% per year after 2013.
14. Accelerated Nuclear and Coal Retirements: Combines the assumptions in the Accelerated Nuclear Retirements and Accelerated Coal Retirements cases.
15. Low Nuclear: Begins with the Accelerated Nuclear Retirements case and combines with assumptions in the High Oil and Gas Resource and the No Sunset cases.
16. High Nuclear: Assumes that all nuclear plants are life-extended beyond 60 years (except for 4.8 GW of announced retirement), and a total of 6.0 GW of uprates. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing.
17. Renewable Fuels Low Renewable Technology Cost: Capital costs for new nonhydro renewable generating technologies are 20% lower than Reference case levels through 2040, and biomass feedstocks are 20% less expensive for a given resource quantity. Capital costs for new ethanol, biodiesel, pyrolysis, and other biomass to liquids (BTL) production technologies are 20% lower than Reference case levels through 2040, and the industrial sector assumes a higher rate of recovery for biomass byproducts from industrial processes.
18. Low Oil and Gas Resource: Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in the Reference case. All other resource assumptions remain the same as in the Reference case.
19. High Oil and Gas Resource: Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells increases 1% per year to reflect additional technological improvement. Also includes kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in the offshore lower 48 states, Alaska, and shale gas in Canada than in the Reference case.
20. Low Coal Cost: Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year higher than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are lower than in the Reference case, falling to about 25% below the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.
21. High Coal Cost: Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year lower than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are higher than in the Reference case, ranging between 24% and 31% above the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.
22. Integrated 2013 Demand Technology: Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2013. Commercial and existing residential building shell efficiency is held constant at

2013 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period.

23. Integrated Best Available Demand Technology: Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. All residential building shells for new construction are assumed to be code compliant and built to the most efficient specifications after 2013, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50% more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case.
24. Integrated High Demand Technology: Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Existing residential building shells exhibit 50% more improvement than in the Reference case after 2013. New and existing commercial building shells are assumed to improve 25% more than in the Reference case by 2040. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, as well as battery electric vehicle costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.
25. Energy Savings and Industrial Competitiveness Act: Begins with the Reference case and assumes passage of the energy efficiency provisions in S. 1392, including appropriation of funds at the levels authorized in the bill. Key provisions modeled include improved national building codes for new homes and commercial buildings and a rebate program for advanced industrial motor systems, assuming the bill's passage in 2014. For new residential construction, building shell efficiencies are assumed to improve by 15% relative to IECC2009 by 2020, and building code compliance is assumed to improve. New commercial building shells are assumed to be 30% more efficient than ASHRAE 90.1-2004 by 2020.
26. Low Electricity Demand: This case was developed to explore the effects on the electric power sector if growth in sales to the grid remained relatively low. Begins with the Best Available Demand Technology case, which lowers demand in the building sectors, and also assumes greater improvement in industrial motor efficiency.
27. No greenhouse gas (GHG) Concern: No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.
28. GHG10: Applies a price for CO_2 emissions throughout the economy, starting at $10/metric ton in 2015 and rising by 5% per year through 2040.
29. GHG25: Applies a price for CO_2 emissions throughout the economy, starting at $25/metric ton in 2015 and rising by 5% per year through 2040.
30. GHG10 and Low Gas Price: Combines GHG10 and High Oil and Gas Resource cases.

IMPA 50 Long-Term Stochastic Draws

To capture long-term uncertainty for its IRP, IMPA extrapolated the trends from the 30 EIA Cases into 50 long-term stochastic draws, which were coupled with IMPA's medium-term and short-term proprietary stochastic draws.

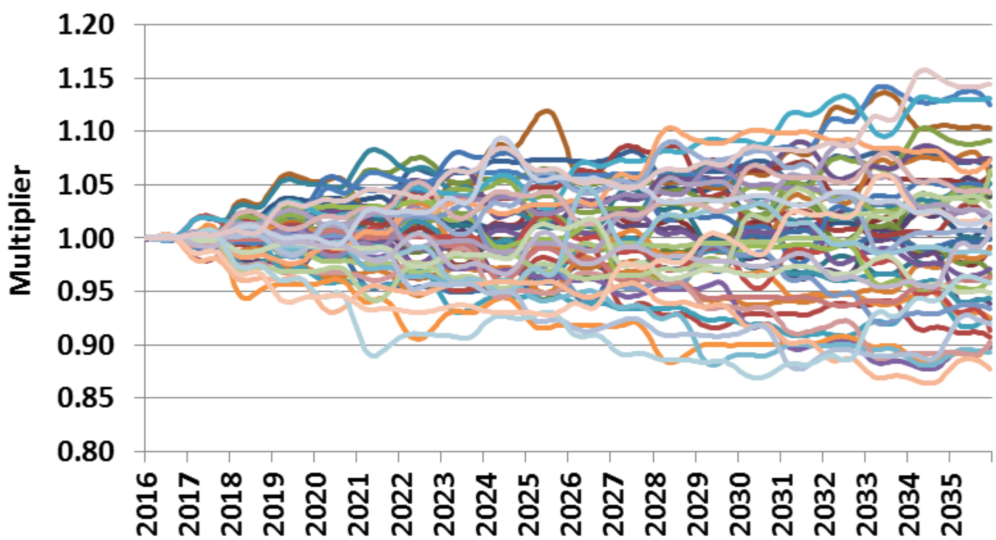
Long-Term Uncertainty – Electricity Demand Growth

The upper bound of the long-term electricity demand growth is tied to the *High Economic Growth* case in which real GDP grows at an average annual rate of 2.8 percent.

The lower bound is tied to the *Low Electricity Demand* case, which explores the effects on the power sector if growth in sales to the grid remained relatively low. This case begins with the *Best Available Demand Technology* case, which lowers demand in the building sectors, and also assumes greater improvement in industrial motor efficiency.

The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 63 Long-Term Electricity Demand Growth – 50 Draws



Source: IMPA

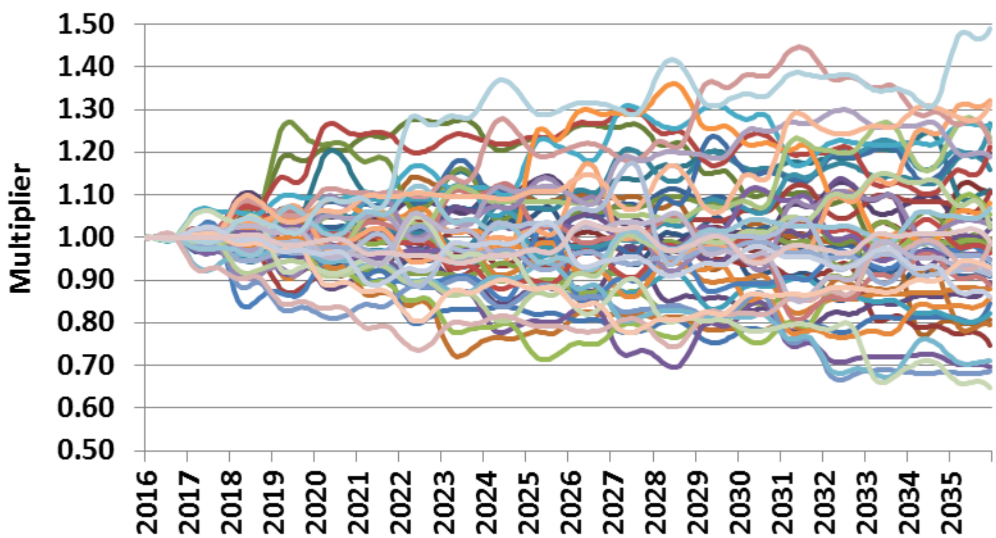
Long-Term Uncertainty – Natural Gas Price

The upper bound of the long-term natural gas price growth is tied to the *Low Oil and Gas Resource* case where the estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than the EIA reference case.

The lower bound is tied to the *High Oil and Gas Resource* case where the estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells increases 1% per year to reflect additional technological improvement. Other factors in this case include kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in the offshore lower 48 states, Alaska, and shale gas in Canada than in the Reference case.

The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 64 Long-Term Natural Gas Price – 50 Draws



Source: IMPA

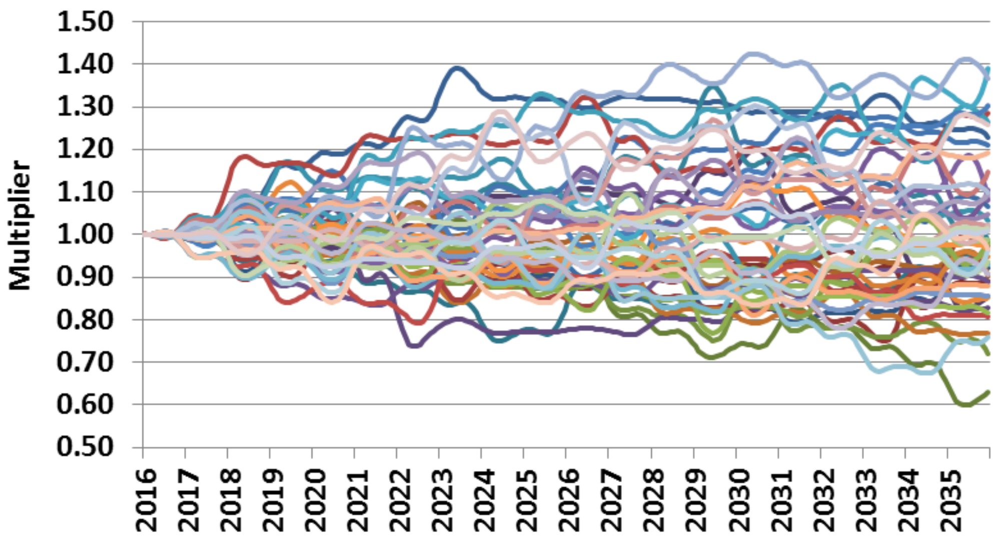
Long-Term Uncertainty – Coal Price

The upper bound of the long-term coal price growth is tied to the *High Coal Cost* case where the regional productivity growth rates for coal mining are approximately 2.3 percentage points per year lower than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are higher than in the Reference case, ranging between 24% and 31% above the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

The lower bound is tied to the *Low Coal Cost* case where the regional productivity growth rates for coal mining are approximately 2.3 percentage points per year higher than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are lower than in the Reference case, falling to about 25% below the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 65 Long-Term Coal Price – 50 Draws



Source: IMPA

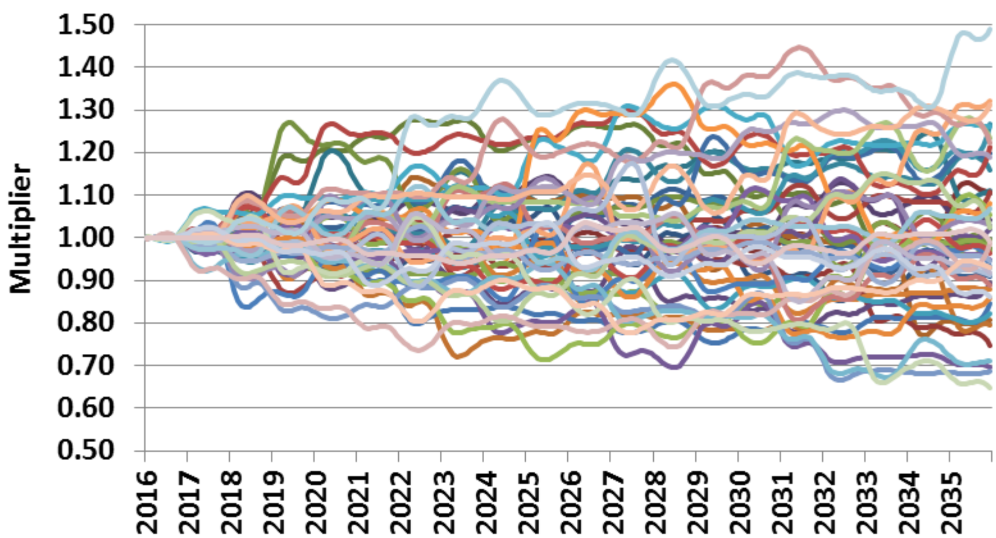
Long-Term Uncertainty – Oil Price

The upper bound of the long-term oil price growth is tied to the *High Oil Price* case where high prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. OPEC market share averages 37% throughout the projection. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $204/barrel (2012 dollars) in 2040.

The lower bound is tied to the *Low Oil Price* case where low prices result from a combination of low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) increases its market share to 51%, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $70/ barrel in 2017 and rise slowly to $75/barrel in 2040.

The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 66 Long-Term Oil Price – 50 Draws



Source: IMPA

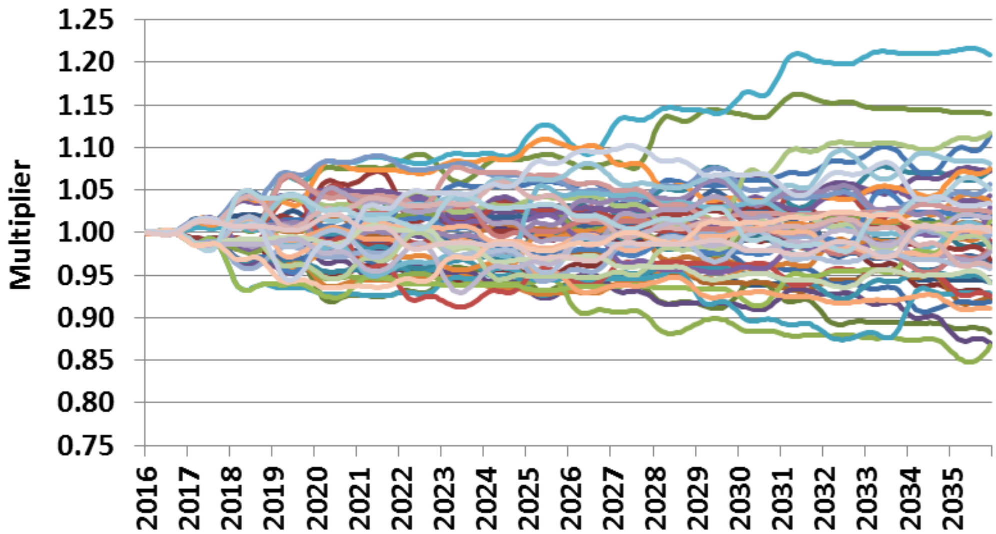
Long-Term Uncertainty – Capital Cost

The upper bound of the long-term capital cost uncertainty is tied to the macroeconomic indicators of the *High Economic Growth* case in which real GDP grows at an average annual rate of 2.8 percent.

The lower bound is tied to the macroeconomic indicators of the *Low Economic Growth* case where real GDP grows at an average annual rate of 1.9% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case.

The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 67 Long-Term Expansion CapX – 50 Draws



Source: IMPA

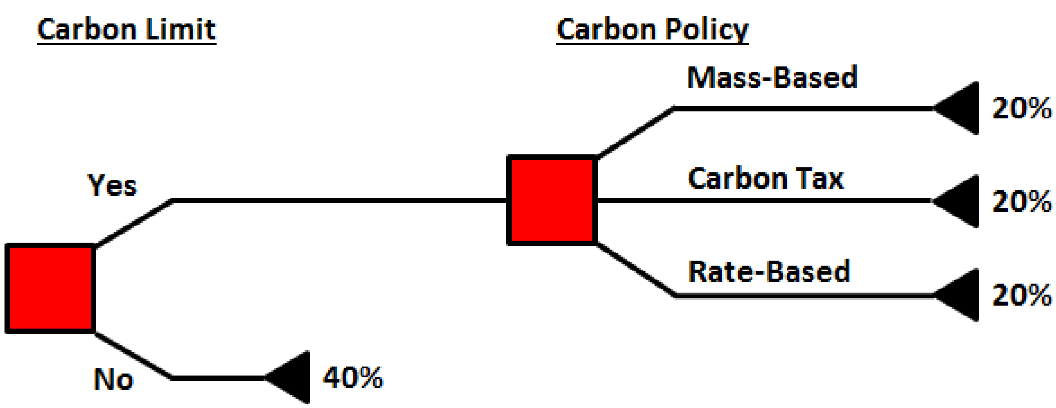
Long-Term Uncertainty – CO_2 Shadow Price

In probability theory, a stochastic process is a collection of random variables representing the evolution of some system of random values over time. The aforementioned long-term variables in this section of the report (demand growth, natural gas price, coal price, oil price, and capital cost) can reasonably be represented by a stochastic process as these variables can be characterized by a distribution (lognormal, normal, uniform, etc.) and a motion (random walking, mean reverting random walk, constant variance, etc.).

However, modeling regulations, rules, and policies stochastically, while possible, is not as straightforward.

As described earlier, for its stochastic process IMPA creates 50 stochastic futures. To incorporate the uncertainty of carbon limits, IMPA randomly assigned a carbon future to each stochastic future. IMPA stakeholders assigned a 60% probability that CO_2 annual limits would be enacted in 2022 and a 40% probability they would not. If the random draw was "Carbon Limit = Yes", then a second random draw was made for the type of carbon policy (massed-based, carbon tax, rate-based). Each of these carbon policies was assigned an equal probability of occurrence. IMPA did not correlate the carbon policy draws to any of the other stochastic input variable; however, through the simulation in Horizons Interactive market module the carbon policy has a pronounced impact on build decisions, market prices, capacity prices, and of course CO_2 prices. The decision tree illustrating this process is shown below.

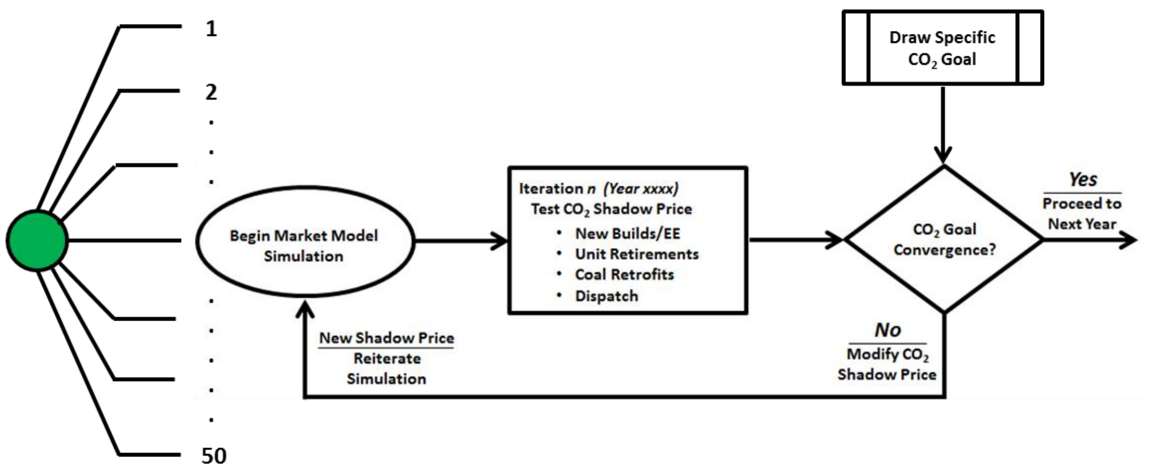
Figure 68 Carbon Future Decision Tree



MASS-BASED	CARBON TAX	RATE-BASED
- Interstate Cap and Trade - Units allocated proportionate share of state's CO_2 allowances based on 2010-2012 emissions - All carbon emitting units over 25 MW participate in trading program	- Tax on each ton of CO_2 emitted - 70% of collected tax rebated to residential rate payers - All carbon emitting units over 25 MW are taxed	- CO_2 emission rate limits - Units reduce emission rates by adding ERCs to the denominator - Only affected EGUs are subject to CO_2 emission rate limits

To determine the value of carbon in the absence of an actual carbon market, IMPA calculates a shadow price of carbon under the market and regulatory conditions of each stochastic draw. Shadow pricing is a method of investment or decision analysis that applies a hypothetical surcharge to a given commodity (in this case carbon emissions) which in turn affects generation additions, energy efficiency, retirements, retrofits, and ultimately the market model dispatch. By entering an annual CO_2 emission goal specific to each stochastic draw, the model will iterate with modified shadow prices until the annual CO_2 goal is achieved. The convergent shadow price is the value of CO_2.

Figure 69 CO_2 Stochastic Shadow Price Flowchart



Calculating stochastic shadow prices provides the most dynamic price of CO_2, taking into account the changing market and regulatory environment of each stochastic draw. Modeling CO_2 using this methodology produces a much more realistic variation in annual CO_2 prices than a simple stream of ever escalating prices per draw.

Figure 70 Long-Term CO_2 Shadow Price – 50 Draws (Horizons)

Source: IMPA

14.2 Mid-term Uncertainties

IMPA built its mid-term stochastic draws based on historical volatilities, standard deviations, and correlations.

Mid-Term Uncertainty – Peak and Energy

Monthly peak and monthly energy are constant variance variables (i.e. the variance remains constant over time) with normal probability distributions. For constant variance variables, monthly variability is expressed in terms of the normalized standard deviation (Std Dev/Mean) for the month. To derive the regional values for monthly peaks, IMPA calculated the average standard deviation of the regional, growth-adjusted historical peaks by month. A parallel methodology was used to derive the standard deviations for monthly energy. The correlation between the regional historical monthly peak and energy values are incorporated into the uncertainty analysis.

The table below shows typical monthly normalized standard deviations for monthly peak and energy uncertainty variables. The correlation coefficients are also included.

Table 14 Peak and Energy Standard Deviations

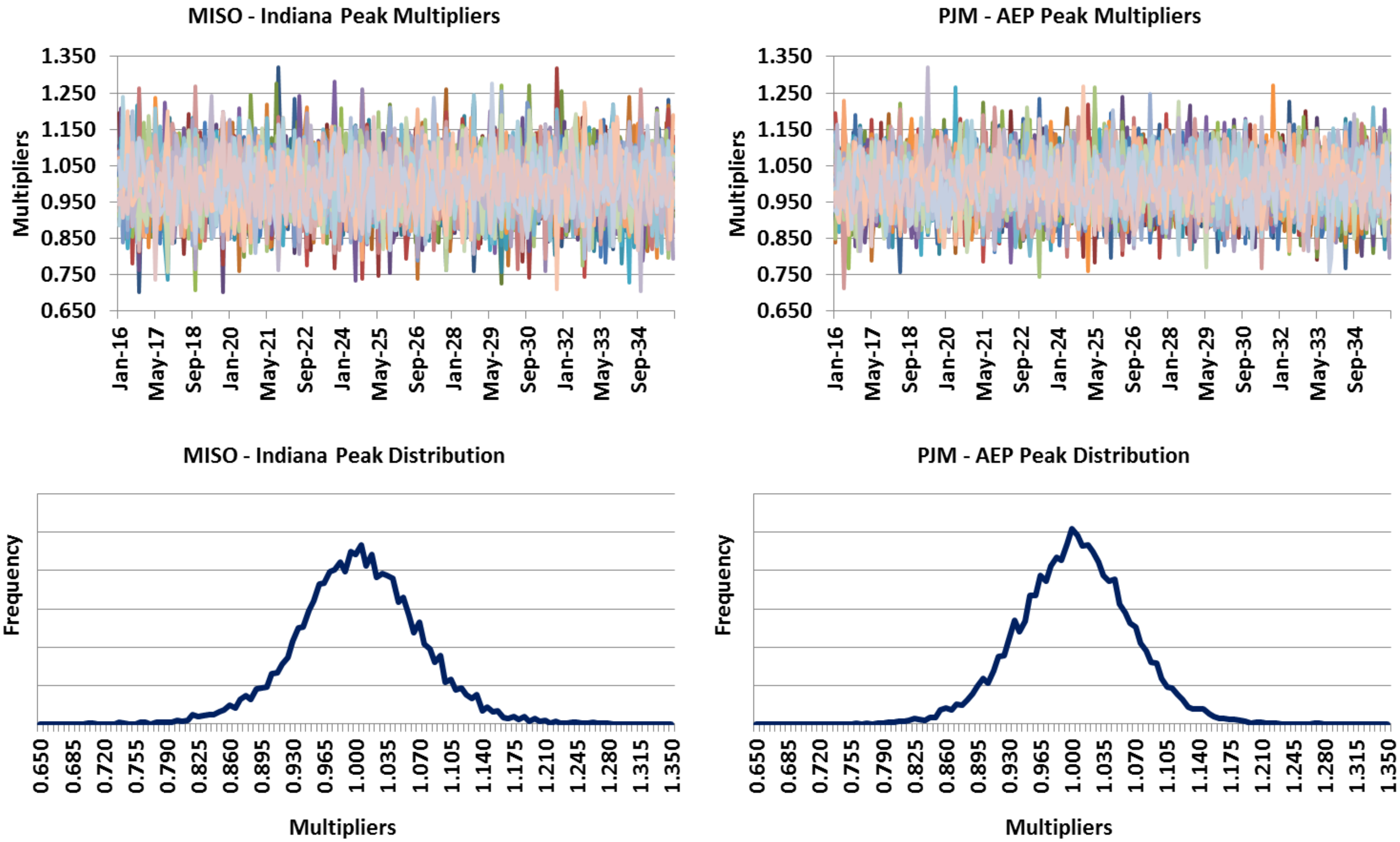
	Peak Standard Deviation	Energy Standard Deviation	Peak - Energy Correlation
Jan	0.0848	0.0740	0.9120
Feb	0.0798	0.0788	0.8596
Mar	0.0807	0.0721	0.8766
Apr	0.0799	0.0655	0.7653
May	0.0975	0.0676	0.6936
Jun	0.0842	0.0744	0.8293
Jul	0.0839	0.0825	0.9168
Aug	0.0739	0.0723	0.9105
Sep	0.0884	0.0712	0.7706
Oct	0.1026	0.0629	0.7393
Nov	0.0715	0.0647	0.8702
Dec	0.0867	0.0767	0.9037

Source: IMPA

These parameters are used by the stratified Monte Carlo sampling program to develop a statistically consistent set of uncertainty multipliers. The resulting monthly peak and energy multipliers are then used to modify the input market-area forecasts.

MISO - Indiana and PJM - AEP peak multipliers are shown following figures (50 x 12 x 20 = 12,000 data points).

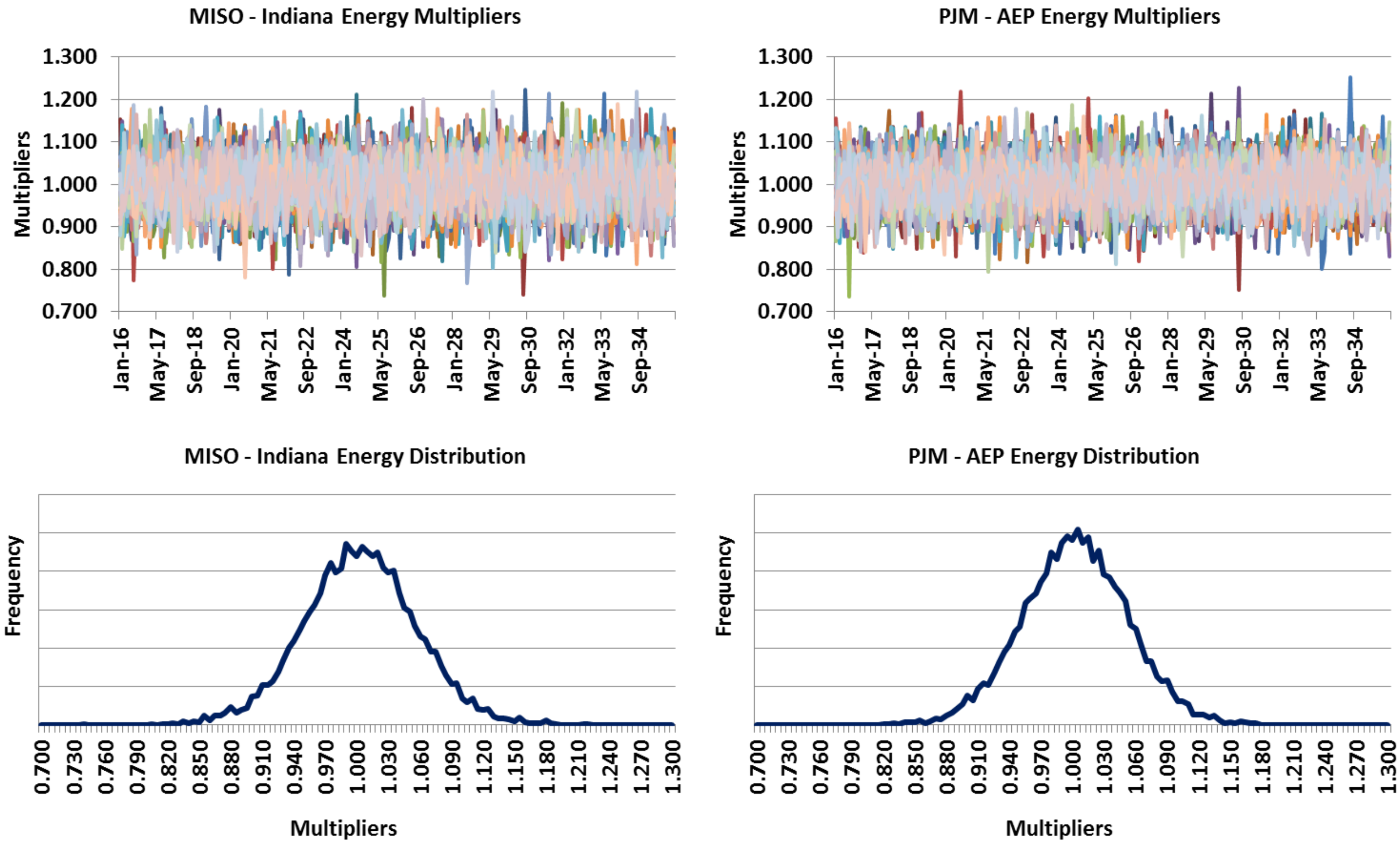
Figure 71 Monthly Peak Multipliers



Source: IMPA

MISO - Indiana and PJM - AEP energy multipliers are shown following figures (50 x 12 x 20 = 12,000 data points).

Figure 72 Monthly Energy Multipliers



Source: IMPA

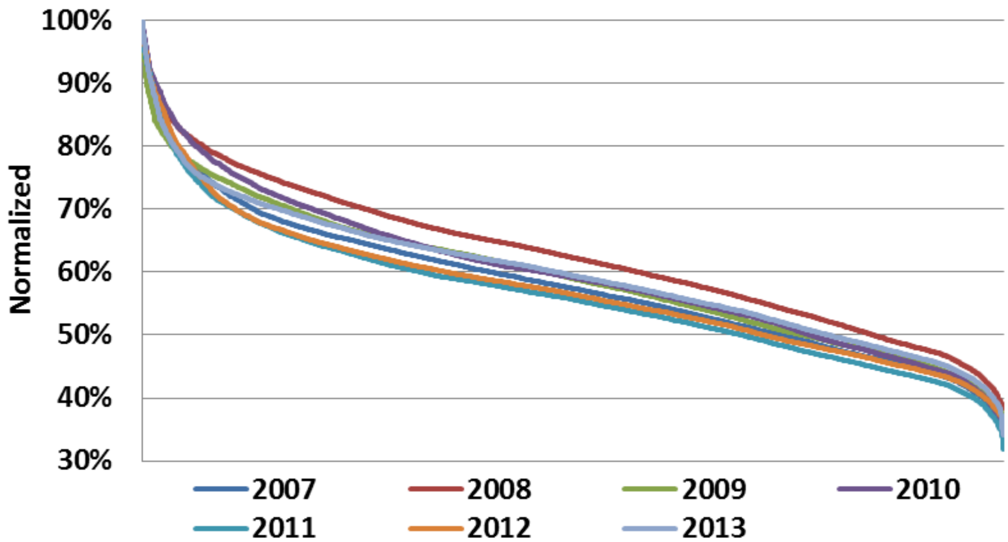
Mid-Term Uncertainty – Reference Hourly Shapes

The Horizons Interactive market model maintains a library of historical hourly shapes for load, wind patterns, solar patterns, and nodal basis spreads.

- Load Patterns: Hourly shapes are available for each of the 192 balancing authorities in North America.
- Wind Patterns: Hourly shapes are derived from 84 airport sites converted to 80 meter wind power curves.
- Solar Patterns: Hourly shapes are created for 64 locations using the PV Watts Calculator.
- Nodal Basis Spreads: Hourly multipliers are available for the 12 nodal points of interest described earlier in this section.

For each year of a given stochastic future (draw 1, draw 2, etc.), a correlated shape for each of the four variables is drawn from the years 2007-2013 using a uniform distribution. By randomizing the shape for each draw, consideration is given to the various weather patterns and temperatures that exist across the geographic regions of the market model. The graph below illustrates IMPA's weather normalized load shapes for the years 2007-2013 shown as a duration curve.

Figure 73 IMPA Historical Normalized Load Shapes

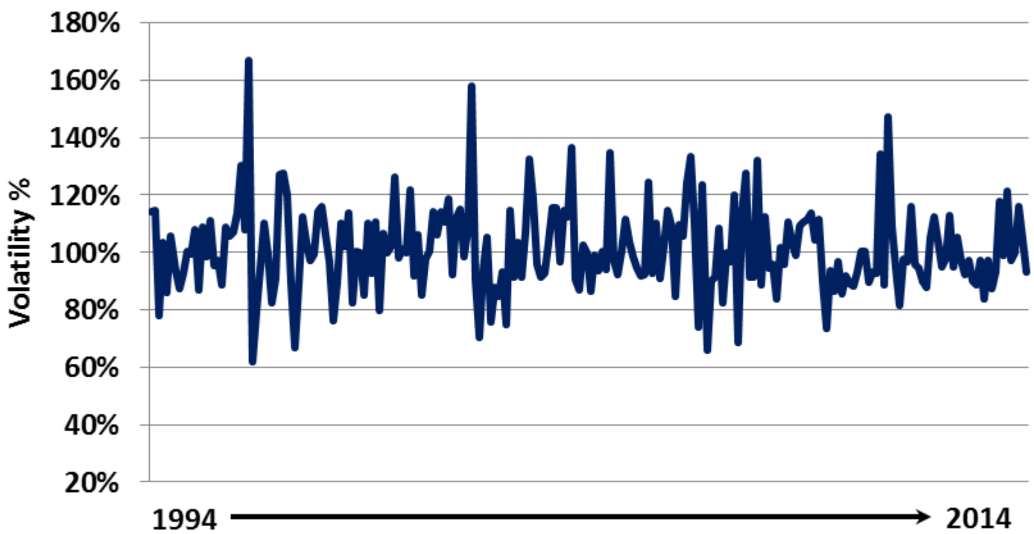


Source: IMPA

Mid-Term Uncertainty – Natural Gas Price

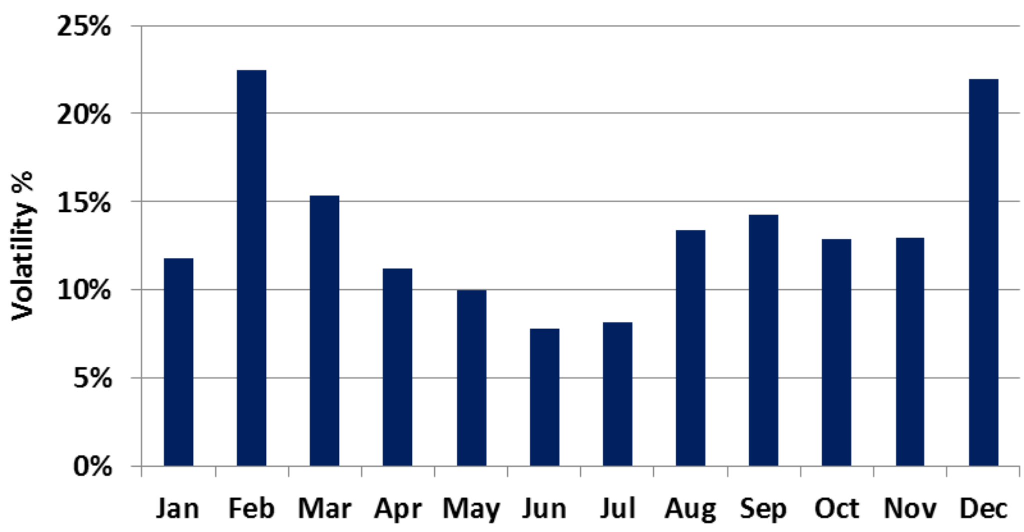
As shown in the graph below, mid-term natural gas price exhibits a mean reverting random walking behavior. That is, over some definable period of time, the price of the commodity tends to move back toward the mean value. To capture mid-term natural gas price uncertainty, IMPA combines monthly volatility with a mean reversion time. Natural gas volatility is month specific as the volatility is greater during the winter heating season and less during the summer season.

Figure 74 Mid-Term Natural Gas Volatility (1994-2014)



Source: IMPA

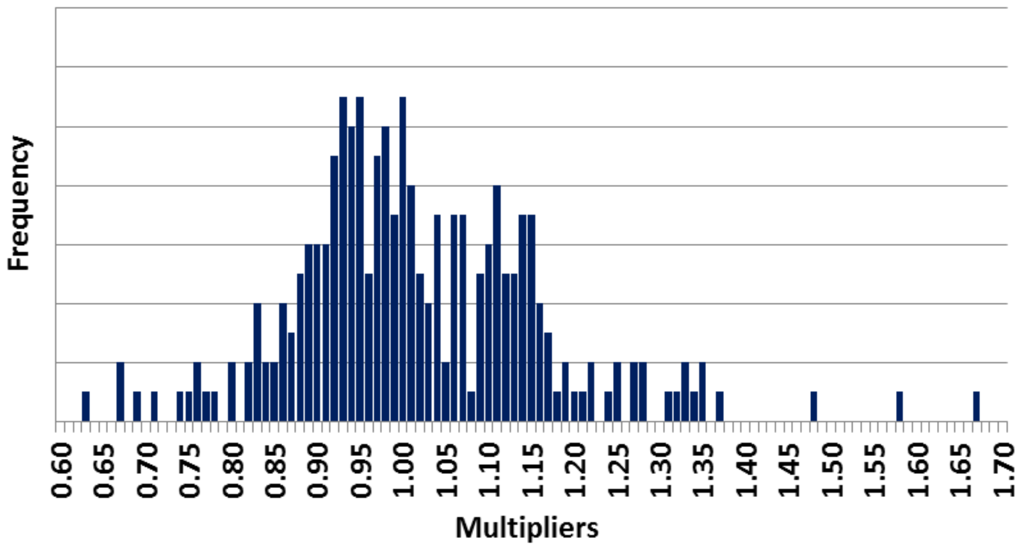
Figure 75 Mid-Term Natural Gas Volatility (Monthly)



Source: IMPA

As shown by the graph below, the distribution of mid-term natural gas price follows a lognormal distribution. The distribution is asymmetric, positively skewed, and as a lognormal distribution assumes that natural gas prices cannot be negative.

Figure 76 Mid-Term Natural Gas Lognormal Distribution



Source: IMPA

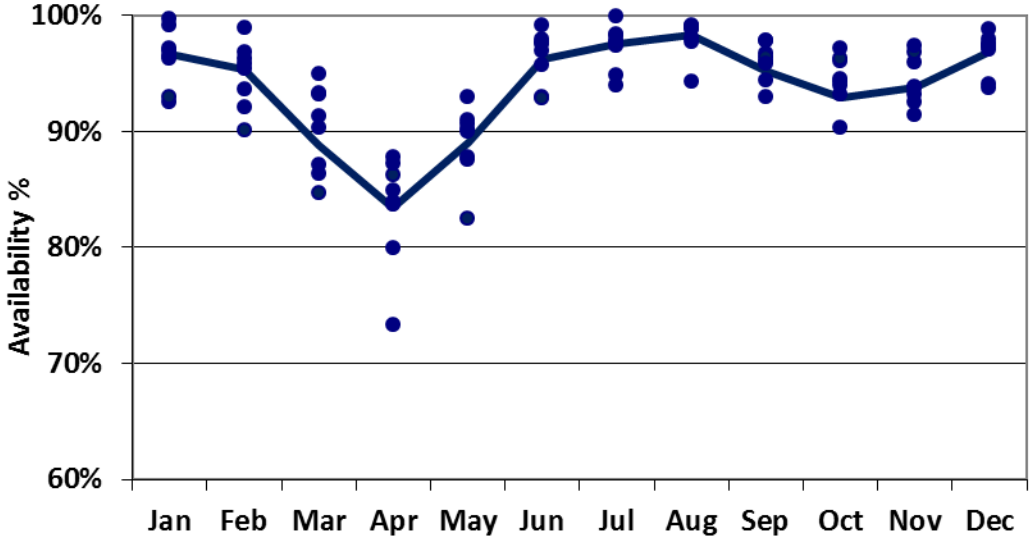
Mid-Term Uncertainty – Coal Unit Availability

Coal unit forced and planned outages are modeled as unit derates in the Horizons Interactive market model. The aggregated coal unit availability within any single zone is a function of the forced and planned outages of each individual unit and the number of units in the zone. So, if there is a single coal unit in a zone, then the coal unit availability would be very volatile. Conversely, if there are many coal units in the zone, then the availability would be less volatile as the risk is spread across many units.

IMPA calculates the historical coal availability exhibited by each zone. Since it is impossible to know the planned outage schedule of all coal units in the market model, the monthly volatility provides a reasonable assumption of when forced and planned outages may occur.

The graph below illustrates the monthly expected availability and range of uncertainty of coal units in the MISO – Indiana zone. This zone represents nearly 15,000 MW of coal generation.

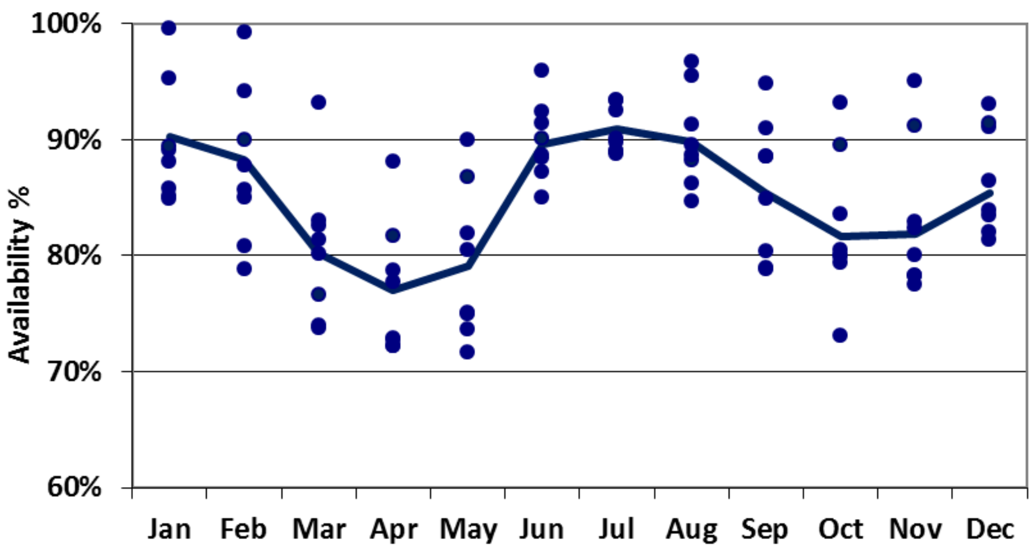
Figure 77 Mid-Term Coal Unit Availability (MISO - Indiana Zone)



Source: IMPA

The following graph illustrates the monthly expected availability and range of uncertainty of coal units in the PJM - AEP zone. This zone represents slightly over 28,000 MW of coal generation. The availability of the PJM – AEP coal units is not as great as is the MISO – Indiana coal units.

Figure 78 Mid-Term Coal Unit Availability (PJM - AEP Zone)

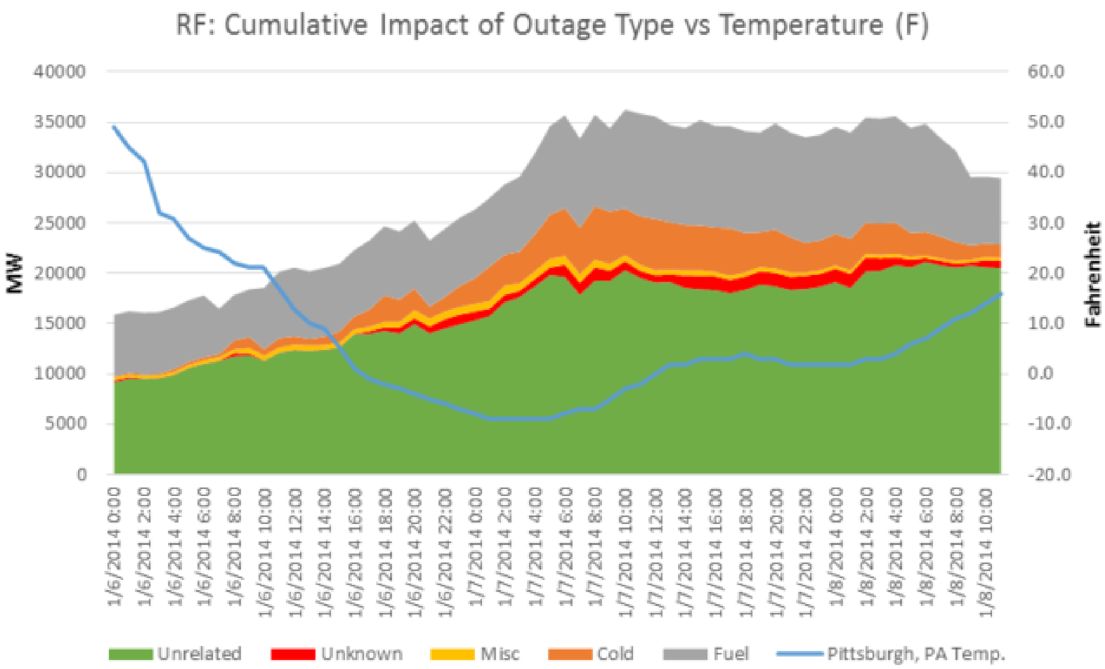


Source: IMPA

Polar Vortex

In early January of 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30° F below average. The extreme cold increased demand for natural gas causing supply curtailments, stressed the generating units resulting in more forced outages, and set all-time peak demand records. As shown in the graph below, ReliabilityFirst experienced the greatest number of generator outages of all the Regions. The cold weather produced just over 5,300 MW of outages with an additional 10,700 MW of fuel-related outages.

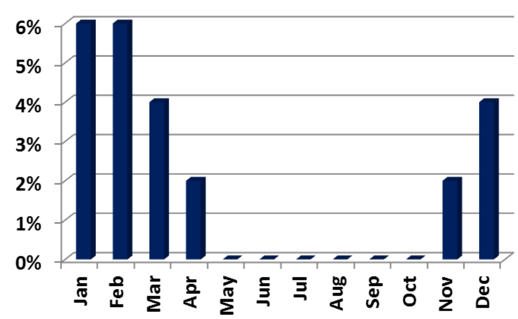
Figure 79 Polar Vortex Impact - ReliabilityFirst



Source: NERC | Polar Vortex Review | September 2014

IMPA stochastically modeled the impact of a polar vortex by assuming a probabilistic percentage of occurrences across the 50 stochastic draws, by month, by year (see graph to the right). The draws, which produce a natural gas supply curtailment in the northern regions for interruptible units, were correlated to the highest winter peak demand draws.

Figure 80 Polar Vortex Occurrence %



Source: IMPA

14.3 HORIZONS INTERACTIVE – STOCHASTIC RESULTS

Introduction

As described earlier, IMPA creates 50 stochastic futures and simulates each future in the Horizons Interactive market model. IMPA is interested in hourly zonal and nodal electricity prices, as well as monthly capacity prices and annual CO_2 shadow prices, which will be utilized in the MIDAS Gold portfolio model. From the market model, IMPA is also interested in the market fundamentals which drive price such as the fuel usage, emissions, transmission flows, new builds, etc., as they provide insight into future market conditions, opportunities, and risk.

The MISO – Indiana 7x24 zonal price Redacted. As illustrated by the graph, the near-term market prices are low and less volatile due to low natural gas forwards and lack of CO_2 legislation. As the forward curve for natural gas morphs into the long-term fundamental forecast and the specter of CO_2 legislation looms, the prices increase and become more volatile.

Figure 81 MISO - Indiana Annual 7x24 Market Prices

Source: IMPA

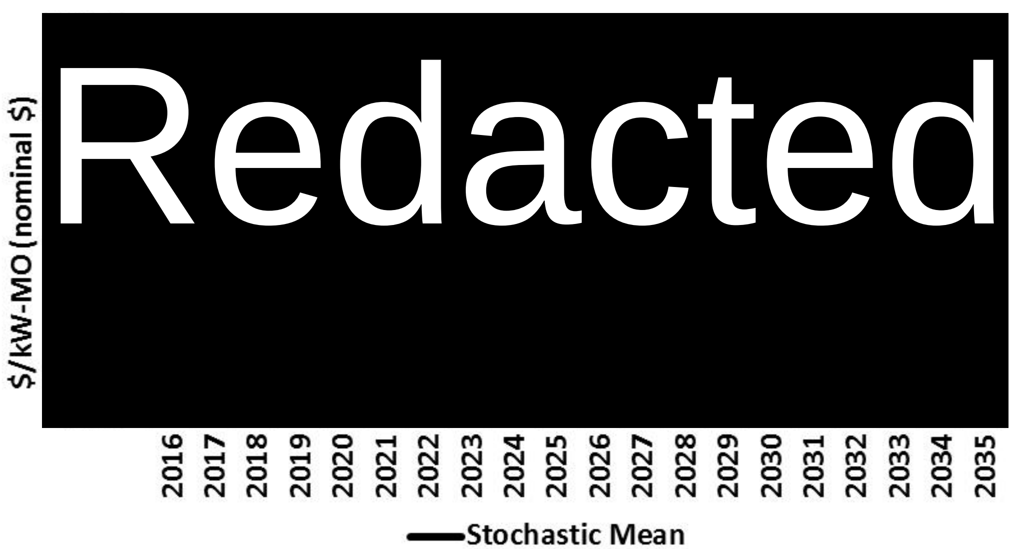
The PJM - AEP 7x24 zonal price [redacted]. The large spikes in market prices reflect the uncertainty in natural gas supply and price, which have a pronounced effect on wholesale electricity prices.

Figure 82 PJM - AEP Annual 7x24 Market Prices

Source: IMPA

Horizons Interactive simulates the MISO cost of new entry (CONE) and a resource adequacy requirements (RAR) curve. For the MISO RTO, IMPA is interested in MISO – Illinois (LRZ4) and MISO – Indiana (LRZ6) capacity prices.

Figure 83 MISO-IL (LRZ4) Capacity Market



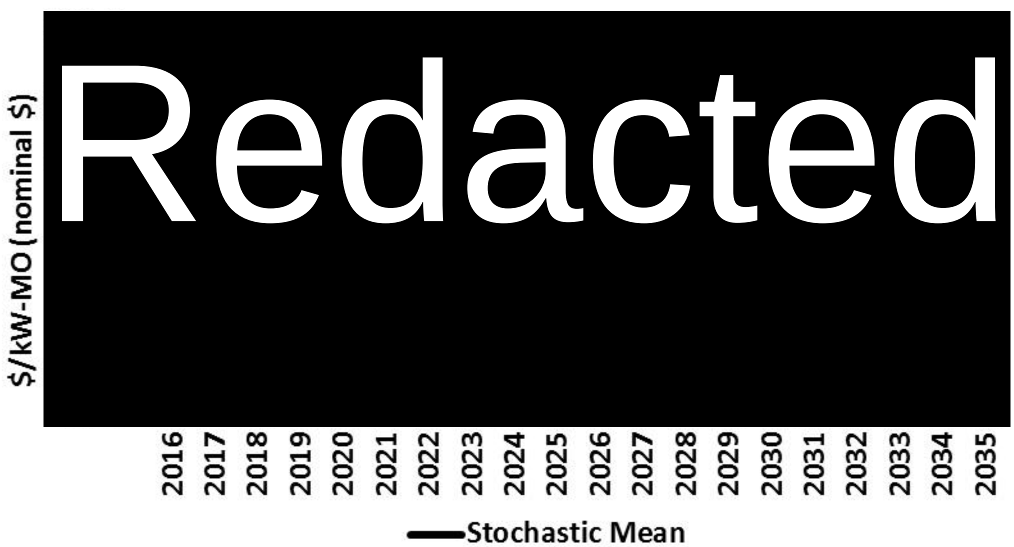
Source: IMPA

Figure 84 MISO-IN (LRZ6) Capacity Market

Source: IMPA

Horizons Interactive simulates the PJM CONE and a variable resource requirement (VRR) curve. For the PJM RTO, IMPA is interested in PJM-RTO capacity prices.

Figure 85 PJM-RTO Capacity Market

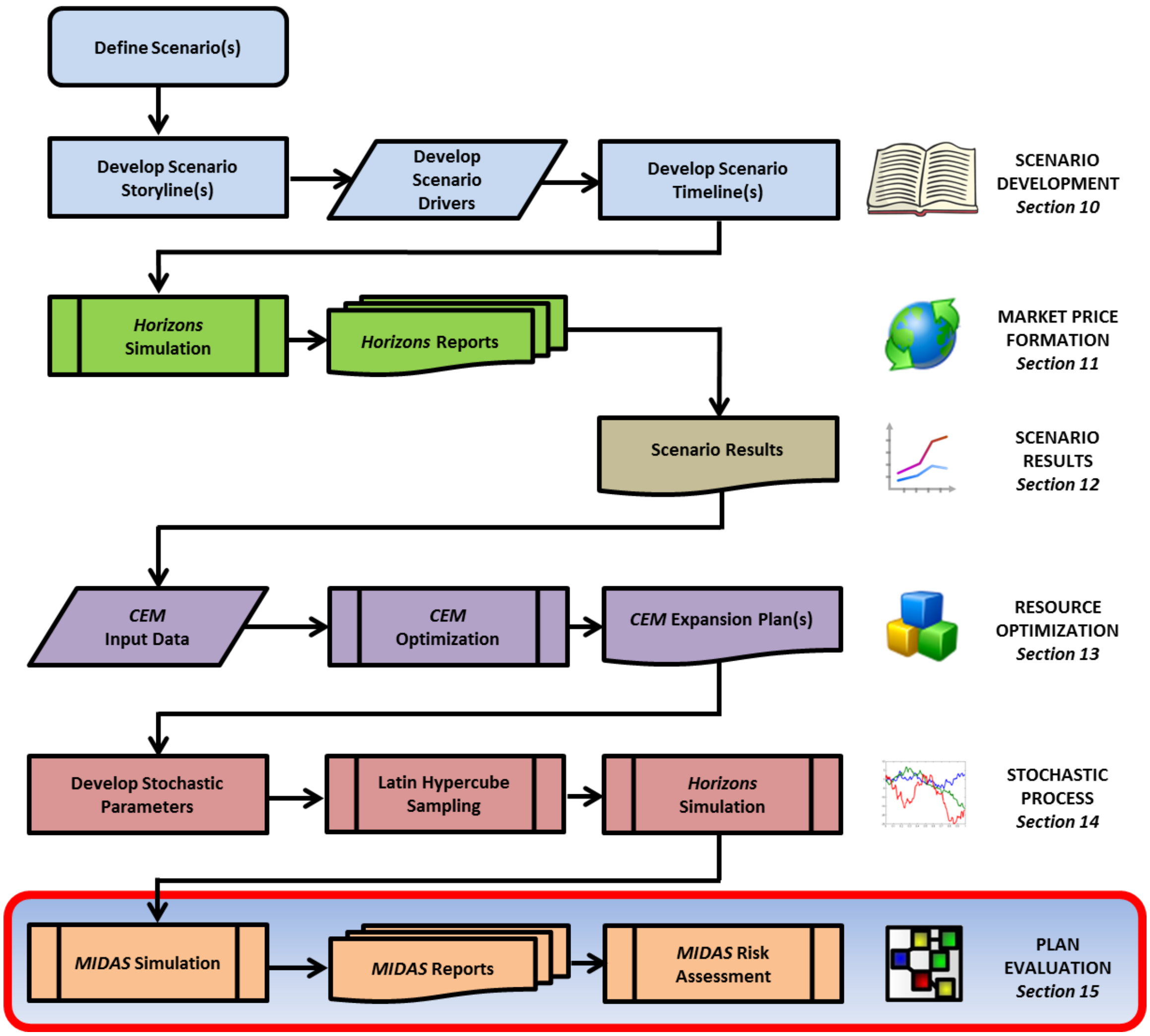


Source: IMPA

15 PLAN EVALUATION

The final step of the IRP Flowchart is detailed analysis of the plans (portfolios) to assess the average system rates, revenue requirements, environmental impacts, and risks associated with each plan. The results and their risk metrics provide IMPA with critical information regarding the cost and robustness of each plan.

Figure 86 IRP Flowchart – Plan Evaluation



15.1 MIDAS GOLD MODULE

Once the optimal resource plans have been identified using the Capacity Expansion module and the price trajectories have been simulated using the Horizons Interactive module, the MIDAS Gold (MIDAS) module is used to perform IMPA-specific portfolio analysis.

Figure 87 MIDAS Gold Module Cut Sheet

MIDAS Gold®

The ***MIDAS Gold®*** portfolio module is designed specifically for energy service providers. **MIDAS Gold® 's** unique ability to combine speed, multiple scenarios, and risk analytics with the integrated capabilities to model the LMP and Capacity market dynamics, operations, customers, and financials, makes it an invaluable tool in the new competitive environment. No other model is as fast, accurate, or reliable. The ***MIDAS Gold®*** portfolio module is composed of three integrated components: ***Transact C, Customer Analyst***, and ***Corporate Finance.***

Transact C

Transact C is a production component providing an hourly, chronological, calendar-correct portfolio dispatch analysis including unit commitment logic and Monte Carlo forced outage simulation. Each generating asset can be assigned to a specific LMP and Capacity market allowing for the proper collection of revenue. Revenues and expenses (fuel, O&M, emissions) are passed to the ***Corporate Finance*** component.

Customer File

Customer File is a customer component that calculates the LMP and Capacity market transactions to drive customer value based on each customer's energy usage, cost to serve, and revenue contribution. Knowing the value that each customer brings to your organization is critical for developing and implementing the targeted marketing, pricing and retention strategies that will enable your company to remain competitive.

Corporate Finance

Corporate Finance is a financial component that produces detailed financial results (e.g. income statements, balance sheets, and cash flow reports) for all levels of the organization - regulated or unregulated - from the parent to subsidiaries to power plants to individual customers. ***Corporate Finance*** is the ideal tool for identifying, measuring, and tracking market-based asset value within an organization. Applications include asset valuation, portfolio management, stranded investment analysis, financial forecasting, and transfer pricing.

MIDAS Gold Module

Source: Ventyx

MIDAS Gold – Operations

MIDAS allows for detailed operational characteristics of IMPA's portfolio. The generation fleet, contracts, and load are dispatched competitively against the LMP market prices created by Horizons Interactive.

The generation fleet dispatch and unit commitment logic allows for unit specific parameters for:

- Heat rates
- Fuel costs
- FO/MO rates
- Variable operation and maintenance (VOM) and fixed operation and maintenance (FOM)
- Emissions
- Ramp rates
- Minimum/maximum run times
- Startup costs

The decision to commit a unit is based on the economics including the cost of shutdown and restarting at a later time. Forced outages may be modeled as Monte-Carlo or frequency and duration with detailed maintenance scheduling.

MIDAS Gold – Rates and Financing

MIDAS creates pro forma financial statements (income statement, balance sheet, cash flow statement) using a middle-up income driver tied to IMPA's debt service coverage (DSC) ratio.

MIDAS Gold – Risk Analyst Tools

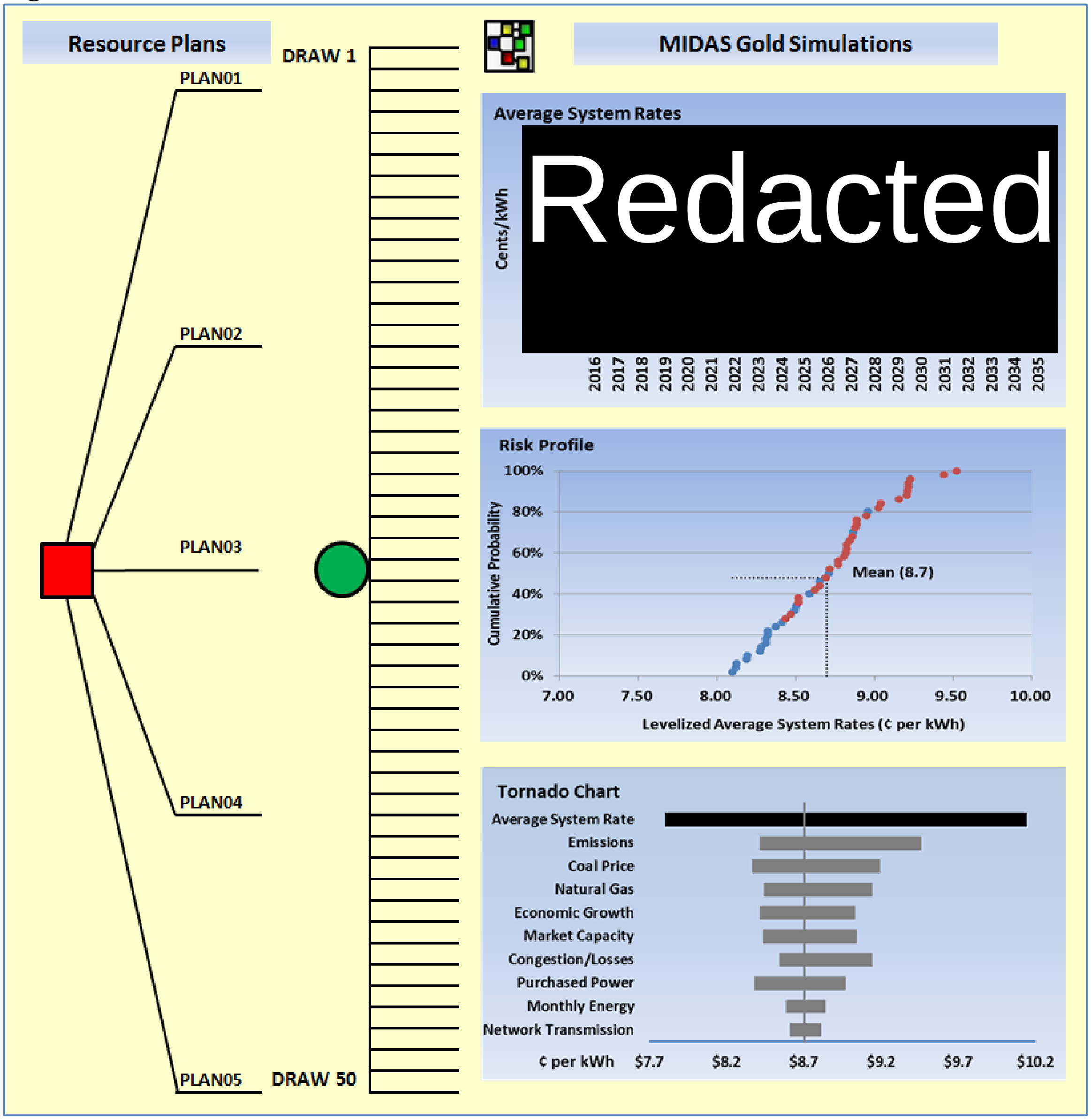
The Risk Analyst tools and techniques provide assessment of the contributors of risk.

- Risk Profiles
- Tornado Charts
- Bar Charts
- Trade-Off Diagrams
- Risk Confidence Band Charts
- Efficient Frontier

MIDAS Gold – Simulation Time

The simulation and processing time for running each of the five (5) plans through the stochastic draws is approximately a half-hour per plan using a desktop PC workstation with 12 GB of RAM, 64-bit operating system, and a 3.2 GHz clock speed. In total, 250 20-year portfolio simulations were performed.

Figure 88 MIDAS Gold Stochastic Process

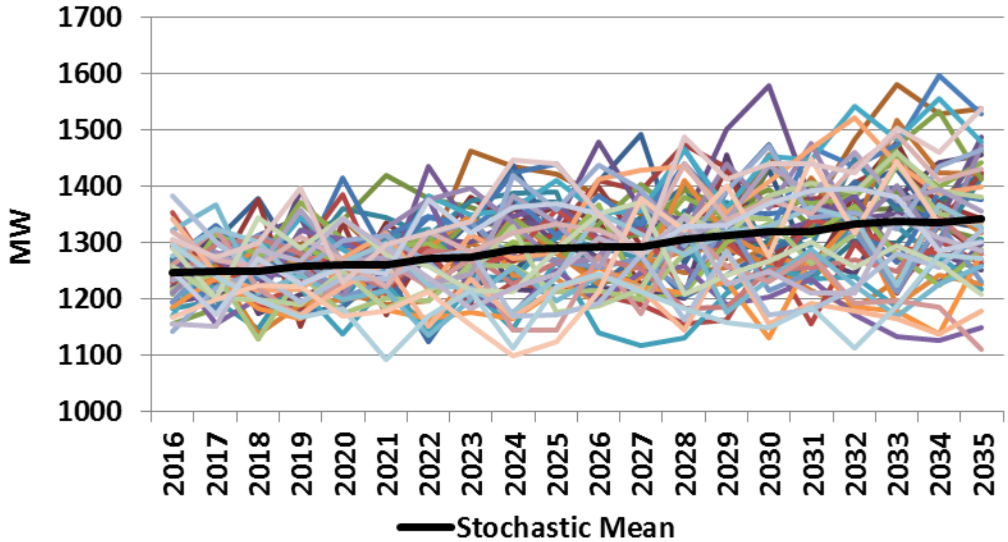


Source: IMPA

IMPA Stochastic Peak Demand

IMPA's peak demand uncertainty is driven by the long-term economic growth combined with the medium-term weather driven peak demand uncertainty.

Figure 89 IMPA Peak Demand – 50 Stochastic Futures

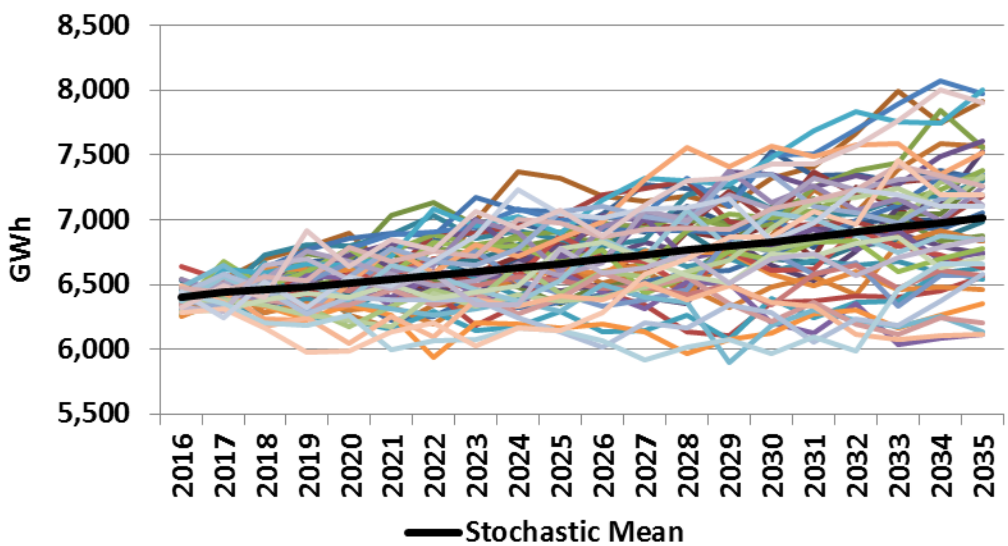


Source: IMPA

IMPA Stochastic Energy

IMPA's annual energy uncertainty is driven by the long-term economic growth and energy efficiency cases combined with the medium-term weather driven energy uncertainty.

Figure 90 IMPA Annual Energy – 50 Stochastic Futures



Source: IMPA

IMPA Stochastic Natural Gas Price

IMPA's natural gas forecast is driven by long-term gas exploration and recovery combined with medium-term volatility driven by usage, storage and weather.

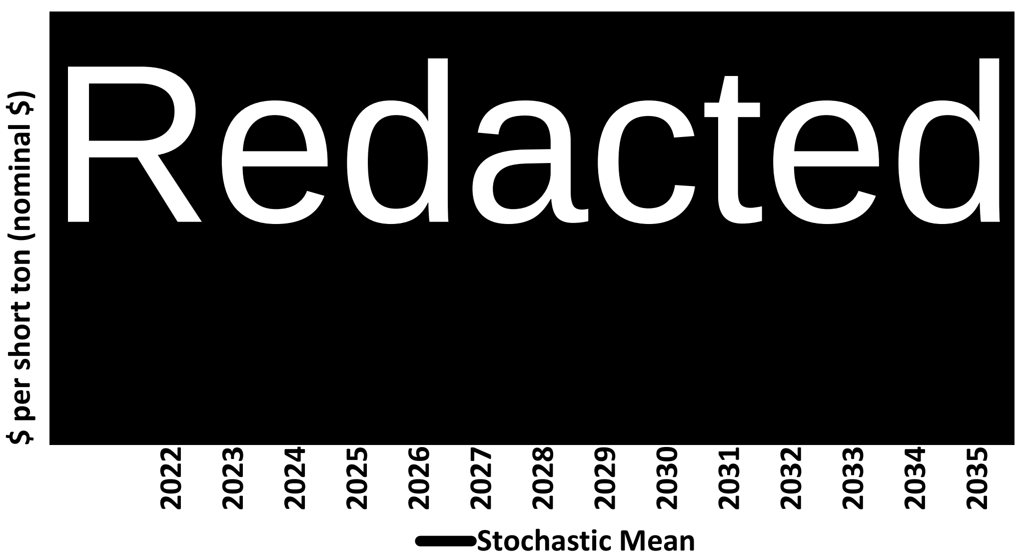
Figure 91 IMPA Natural Gas Price – 50 Stochastic Futures

Source: IMPA

IMPA Stochastic CO_2 Expense

IMPA's CO_2 emission expense is driven by CO_2 shadow price exposure and the number of CO_2 allowances or ERCs required, dependent upon the stochastic draw. Or, in the instance of a carbon tax stochastic draw, the retail customer tax rebate.

Figure 92 IMPA CO_2 Shadow Price – 30 Draws

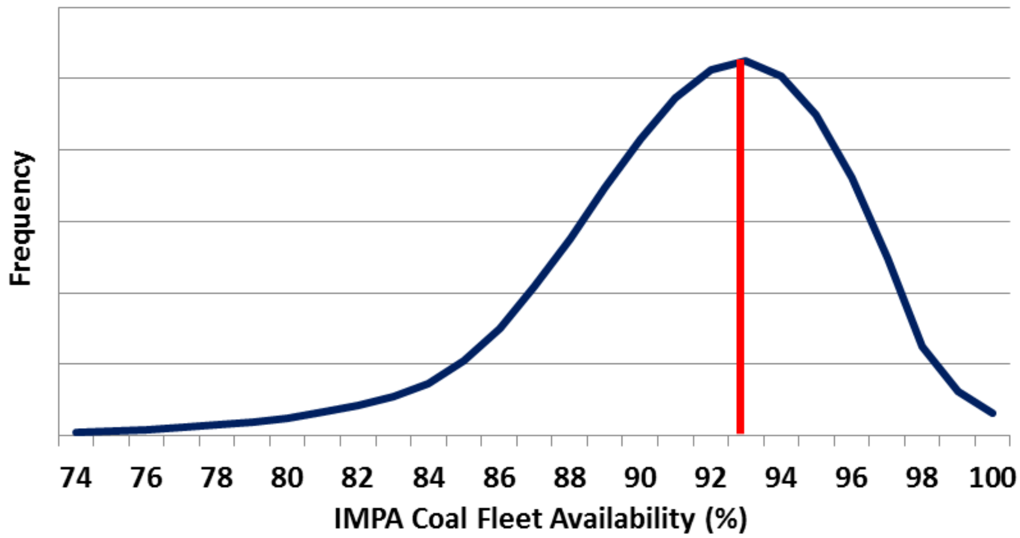


Source: IMPA

IMPA Coal Fleet Availability

IMPA's coal fleet consists of joint-ownership in five (5) large coal units and two (2) smaller coal units which are primarily used for peaking purposes. To capture the uncertainty of one or more of the large coal units experiencing a forced outage, IMPA created a frequency of availability curve shown below. The curve illustrates the frequency of availability for the entire IMPA coal fleet based on data from 100+ similar sized units from the NERC's Generating Availability Data System (GADS) database. The skewed-left lognormal distribution is applied to the Monte Carlo draws of the coal fleet depicting the probabilistic range of availability.

Figure 93 IMPA Coal Fleet Availability



Source: IMPA

15.2 PLAN EVALUATION METHODOLOGY

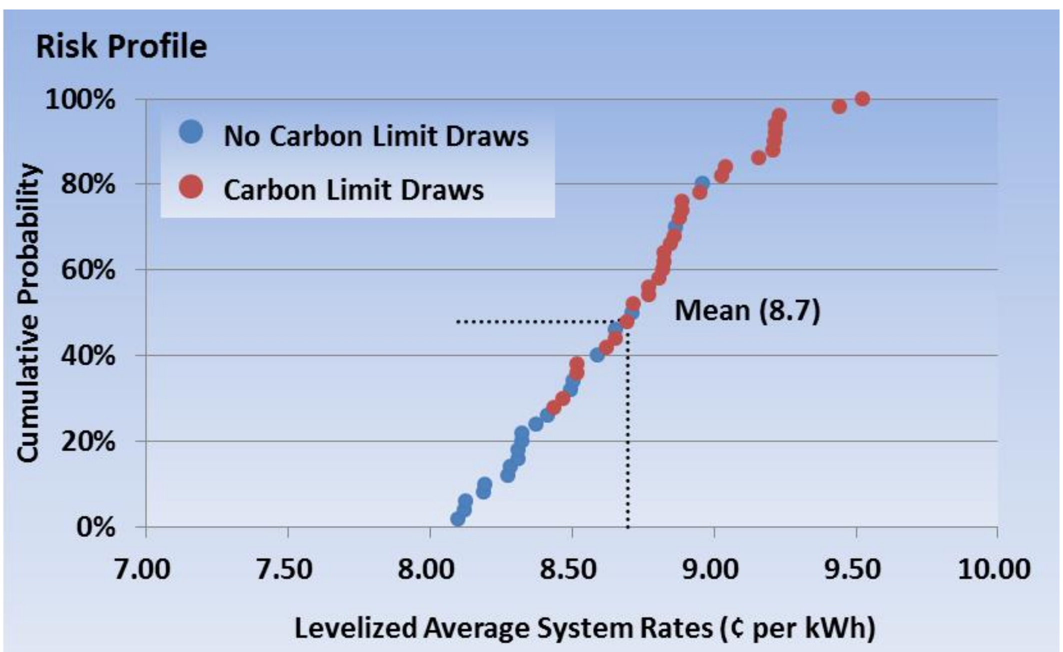
The five plans discussed previously were input into the MIDAS platform and run through the stochastic analysis. The result is 50 sets of output for each plan. This data is analyzed using several techniques, some of which are explained below.

Risk Profiles Explained

The risk profiles created for each plan provide valuable insight into the risk of a particular plan. The x-axis (levelized average system rate) shows the range of possible outcomes, in this case IMPA plots the outcome of fifty (50) stochastic draws. The y-axis is the cumulative probability of occurrence of each outcome between 0% and 100%. For example, if the far left point is 8.1¢/kWh and the far right point is 9.5¢/kWh, then there is 100% confidence that the rate will be between those two points. The more narrow the range, the less risk. As explained in the Stochastic Process (Section 14), it was assumed 60% of the stochastic draws would have a carbon goal and 40% would not. IMPA color-coded carbon draws on the risk profile to identify the carbon limits draws.

To manage risk, risk managers look for ways to minimize the "fat tails" of a risk profile often trading upside opportunity for downside risk. A risk averse profile would be a vertical line, but achieving a risk free vertical line likely moves the entire profile far to the right. Think of it as buying far more insurance than is necessary and laying off the risk on the insurance company. IMPA recognizes there is inherent risk in the electric utility business so a balance is drawn between risk and reward using tools such as a risk profile.

Figure 94 Risk Profile Example



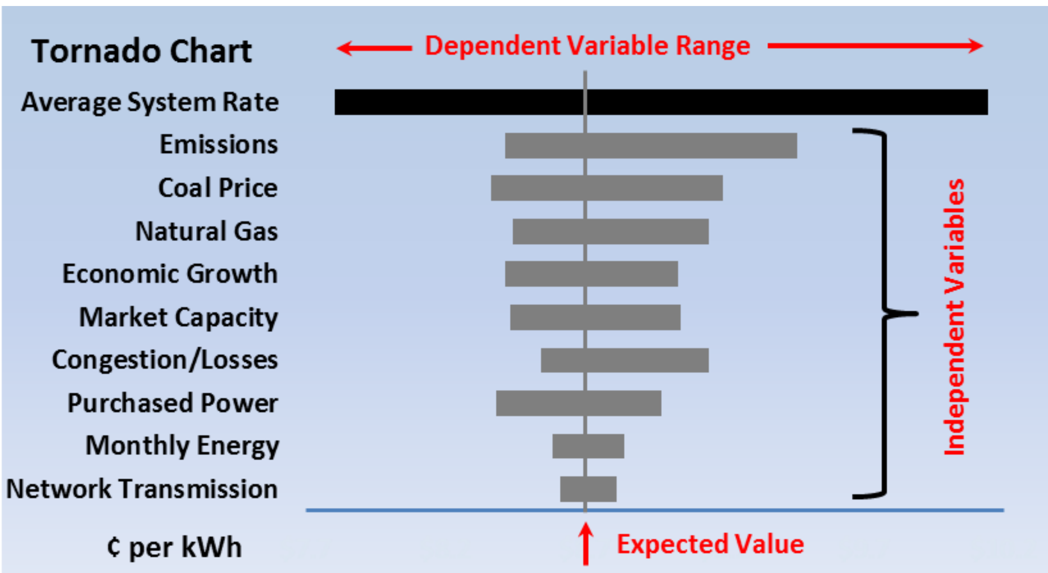
Source: IMPA

Tornado Charts Explained

To understand the risk of the drivers, IMPA creates tornado charts to determine the sensitivity of the various fundamental drivers on average system rates (ASR). As shown in the figure below, ASR (black bar) is the dependent variable and the remaining nine (9) drivers are independent variables (gray bars).

The length of the black bar is the uncertainty range of ASR for a selected time frame. The lengths of the gray bars illustrate each independent variable's impact on ASR; the longer the bar, the greater the impact. The expected value is signified by the vertical line. When a gray bar is off-set to the left that means that independent variable puts downward pressure on ASR (good outcome). Conversely, if the gray bar is off-set to the right, then the independent variable puts upward pressure on ASR (bad outcome).

Figure 95 Tornado Chart Example

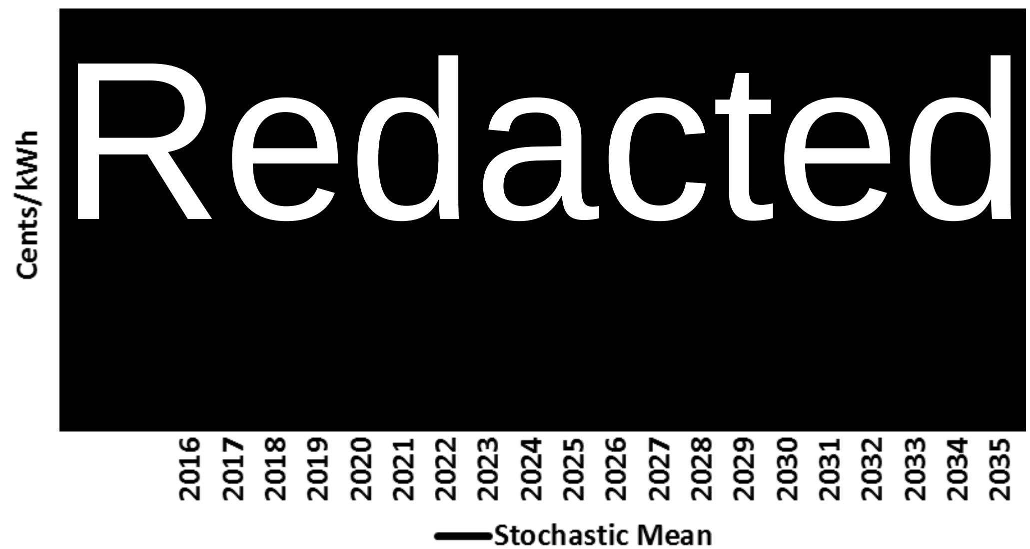


Source: IMPA

15.3 PLAN01 RESULTS

Plan Summary: Plan01 is based on the Status Quo scenario. In this optimization, Whitewater Valley Station (WWVS) is retired in 2022 (90 MW) and new combined cycle units are added in 2021 (200 MW), 2022 (100 MW), and 2034 (200 MW). There is no additional renewable generation other than those currently planned (50 MW of solar) and no energy efficiency.

	Plan 01
Economic Growth	Reference
Capital Construction Cost	Reference
Load Forecast	Reference
Load Factor	Existing
Natural Gas Prices	Reference
Coal Price	Reference
CO_2 Policy	Existing
Reserve Margin	Pool + 1%
Retirements – MW	(90)
Natural Gas Additions – MW	500
Renewables – MW	50
Energy Efficiency – MW	0

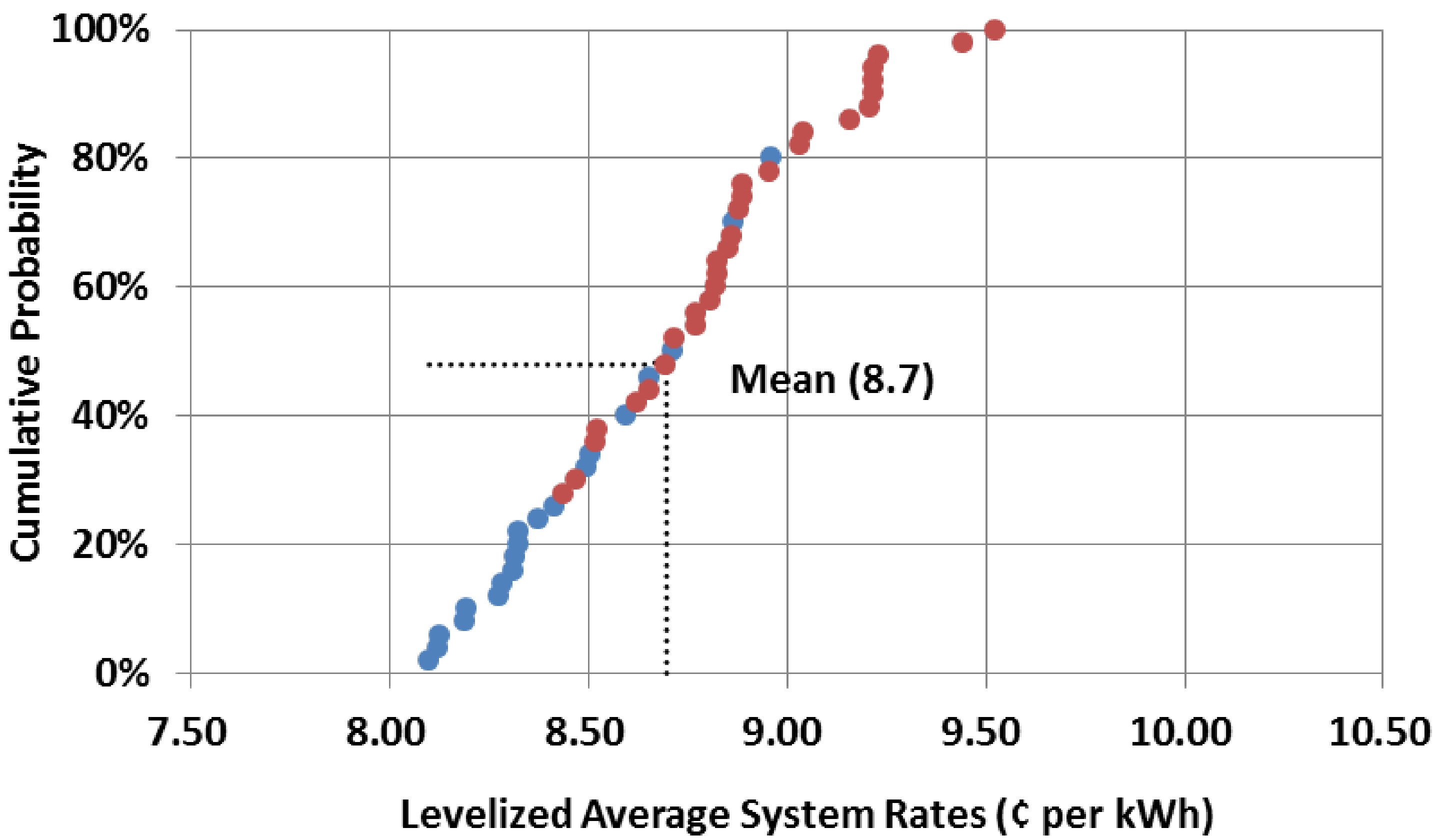


Source: IMPA

Plan Observations: The decision to build CCs in 2021 and 2034 was intuitive as IMPA has capacity needs in those two years. The decision to retire WWVS and replace it with a CC was an economic optimization decision made by CEM. Under the reference assumptions, it made economic sense to retire the coal-fired WWVS which generally operates as a peaking unit and replace it with a highly efficient natural gas CC which operates as a baseload unit.

Risk Profile Observations: Sorting the 20 year levelized costs from the stochastic results produces the cumulative probability graph shown below. The line markers are divided into carbon (red) and non-carbon (blue) stochastic endpoints. The mean levelized average system rate of this plan is 8.70 cents per kWh.

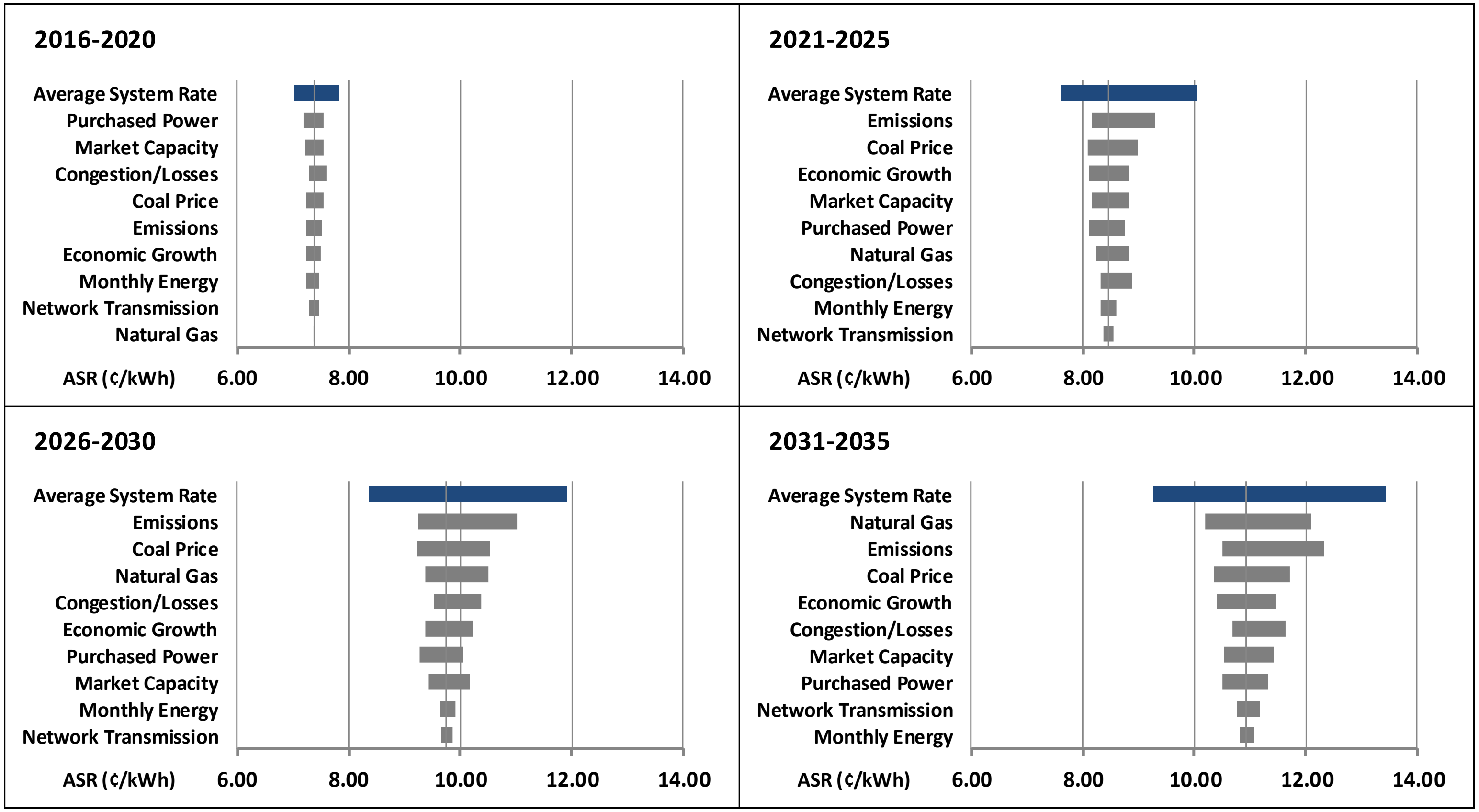
Figure 96 Plan01 Risk Profile



Source: IMPA

Tornado Chart Observations: The following tornado charts summarize the stochastic results in five year blocks. The next five years are fairly stable with low variability expected in the results. This is partly due to IMPA's hedging program which already includes market energy and capacity purchases as far out as 2021. Additionally, the stochastic endpoints containing CO_2 do not begin until 2022. In the next three charts, the exposure due to CO_2 uncertainty is clearly evident as the charts widen significantly. Going forward, CO_2, gas price and coal price are the primary risk factors for IMPA's portfolio.

Figure 97 Plan01 Tornado Charts



Source: IMPA

15.4 PLAN02 RESULTS

Plan Summary: Plan02 is based on the Retrenchment scenario. In this optimization, no units are retired and combined cycle units are added in 2021 (200 MW) and 2034 (200 MW). There is no additional renewable other than those currently planned (50 MW of solar) and no energy efficiency.

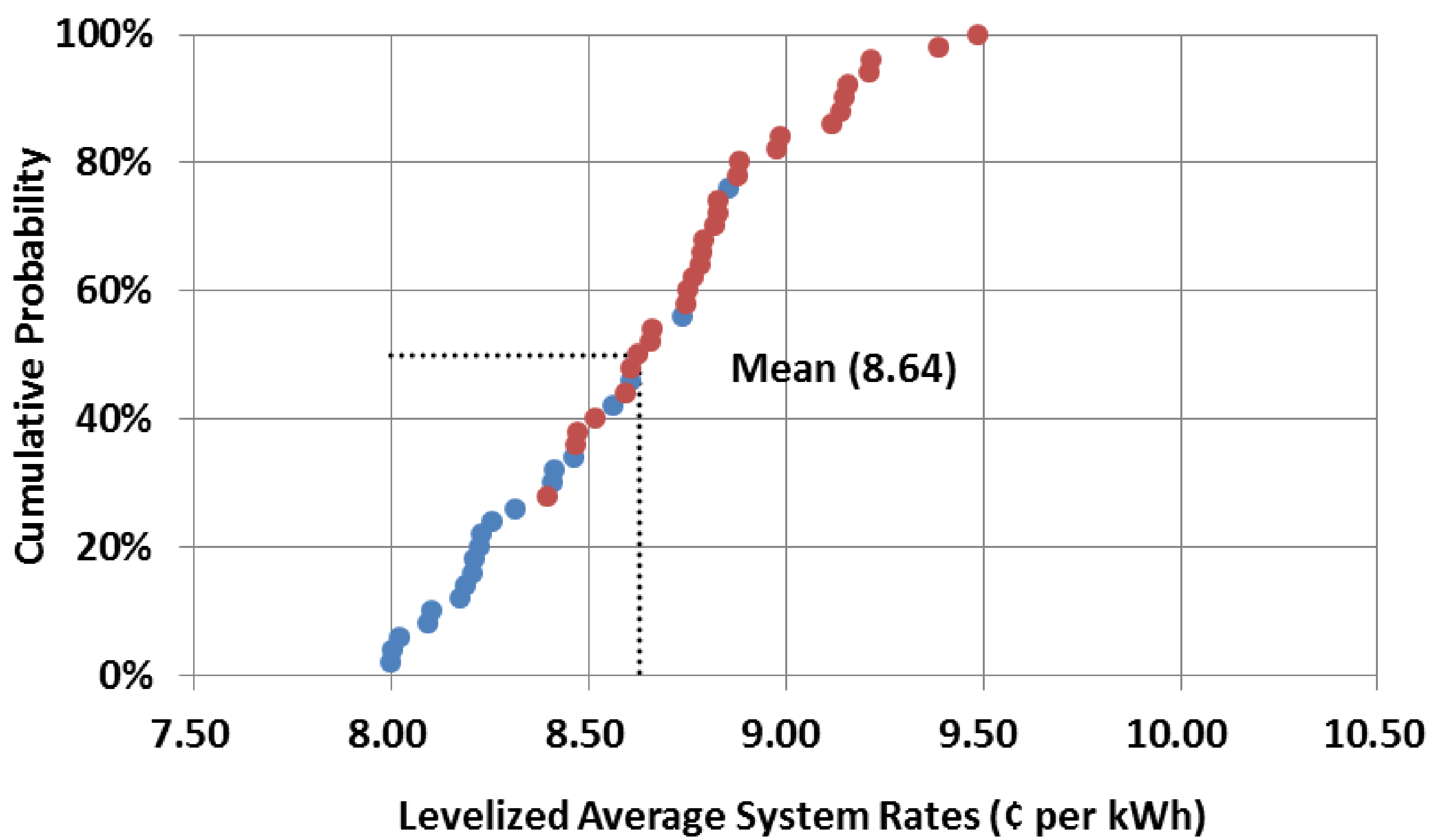
	Plan02
Economic Growth	Med-High
Capital Construction Cost	Low
Load Forecast	Med-High
Load Factor	1.5% Higher
Natural Gas Prices	Low
Coal Price	Low
CO_2 Policy	No Policy
Reserve Margin	Pool + 2%
Retirements – MW	0
Natural Gas Additions – MW	400
Renewables – MW	50
Energy Efficiency – MW	0

Source: IMPA

Plan Observations: The decision to build CCs in 2021 and 2034 is intuitive as IMPA has capacity needs in those two years.

Risk Profile Observations: Sorting the 20 year levelized costs from the stochastic results produces the cumulative probability graph shown below. The line markers are divided into carbon (red) and non-carbon (blue) stochastic endpoints. The mean levelized average system rate of this plan is 8.64 cents per kWh.

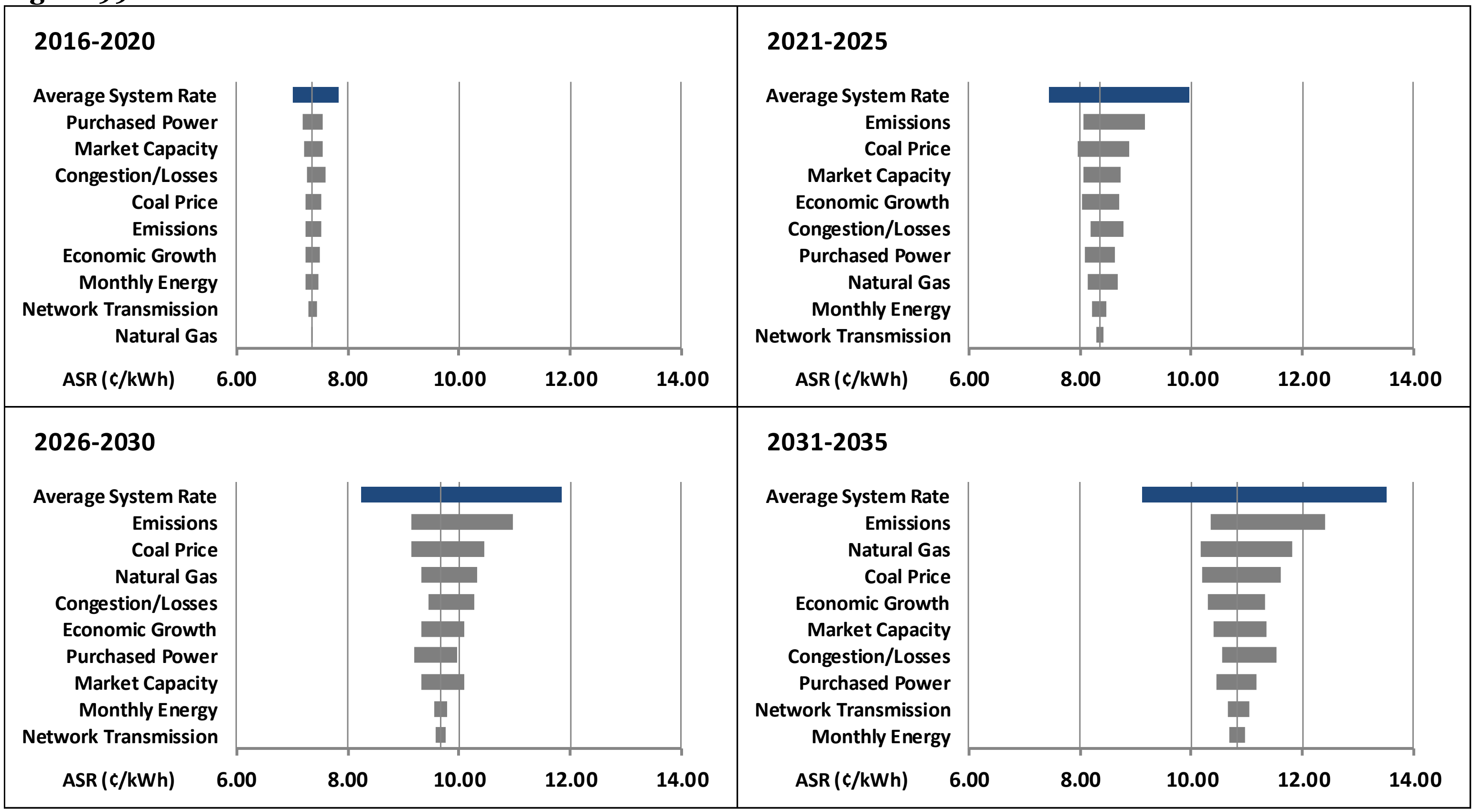
Figure 98 Plan02 Risk Profile



Source: IMPA

Tornado Chart Observations: The following tornado charts summarize the stochastic results in five year blocks. 2016-2020 remains fairly stable as in Plan01. In the next three charts, the exposure due to CO_2 uncertainty is clearly evident as the charts widen significantly. Going forward, CO_2, gas price and coal price are the primary risk factors for IMPA's portfolio in this plan.

Figure 99 Plan02 Tornado Charts

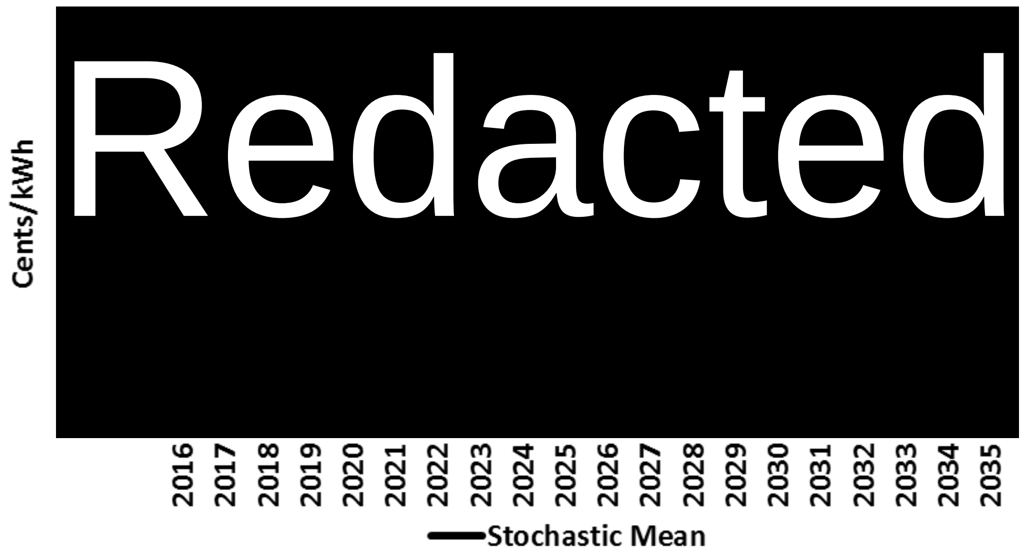


Source: IMPA

15.5 PLAN03 RESULTS

Plan Summary: Plan03 is based on the Global Economy scenario. In this optimization, Whitewater Valley Station (90 MW), Gibson #5 (156 MW) and Trimble County #1 (66 MW) are retired. Combined cycle units are added in 2021 (200 MW), 2022 (300 MW) and 2034 (200 MW). There is no additional renewable other than those currently planned (50 MW of solar). Significant energy efficiency (329 MW) is added in this plan.

	Plan03
Economic Growth	High
Capital Construction Cost	Med-Low
Load Forecast	High
Load Factor	1.5% Lower
Natural Gas Prices	Med-Low
Coal Price	Med-High
CO_2 Policy	Mass-Based
Reserve Margin	Pool Req
Retirements – MW	(312)
Natural Gas Additions – MW	700
Renewables – MW	50
Energy Efficiency – MW	329

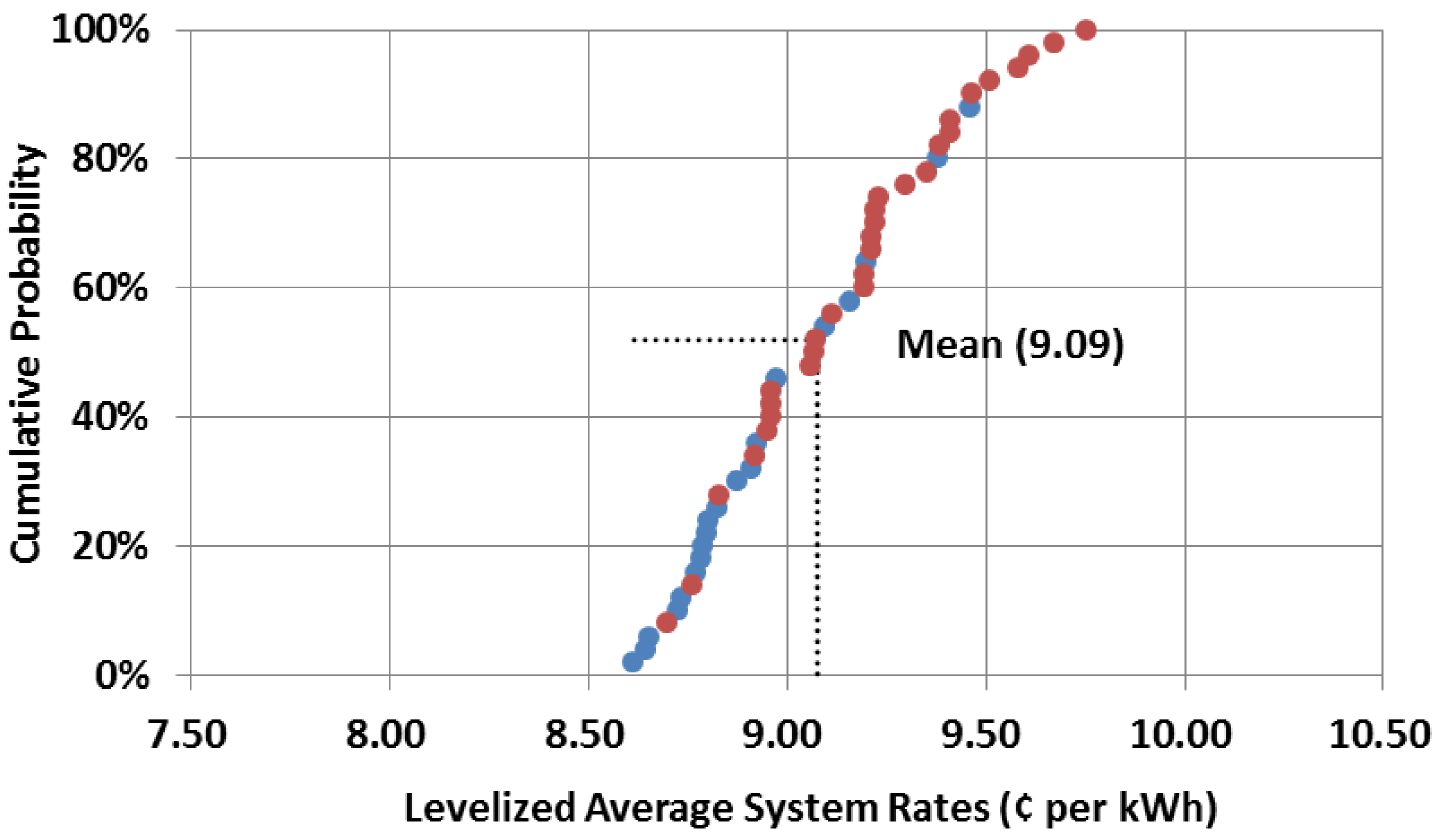


Source: IMPA

Plan Observations: Plan03 is designed to meet the EPA CPP rules through a mass-based approach (interstate cap and trade). This plan was built on a scenario with medium-low natural gas prices coupled with medium-high coal prices. This leads to significant coal retirements (312 MW) combined with a significant addition of CCs (700 MW). The stochastic mean line (black line) illustrates the sharp rate increase required to meet the CPP. This is largely attributable to the energy efficiency load destruction and the CO_2 cap and trade impacts.

Risk Profile Observations: Sorting the 20 year levelized costs from the stochastic results produces the cumulative probability graph shown below. The line markers are divided into carbon (red) and non-carbon (blue) stochastic endpoints. The mean levelized average system rate of this plan is 9.09 cents per kWh.

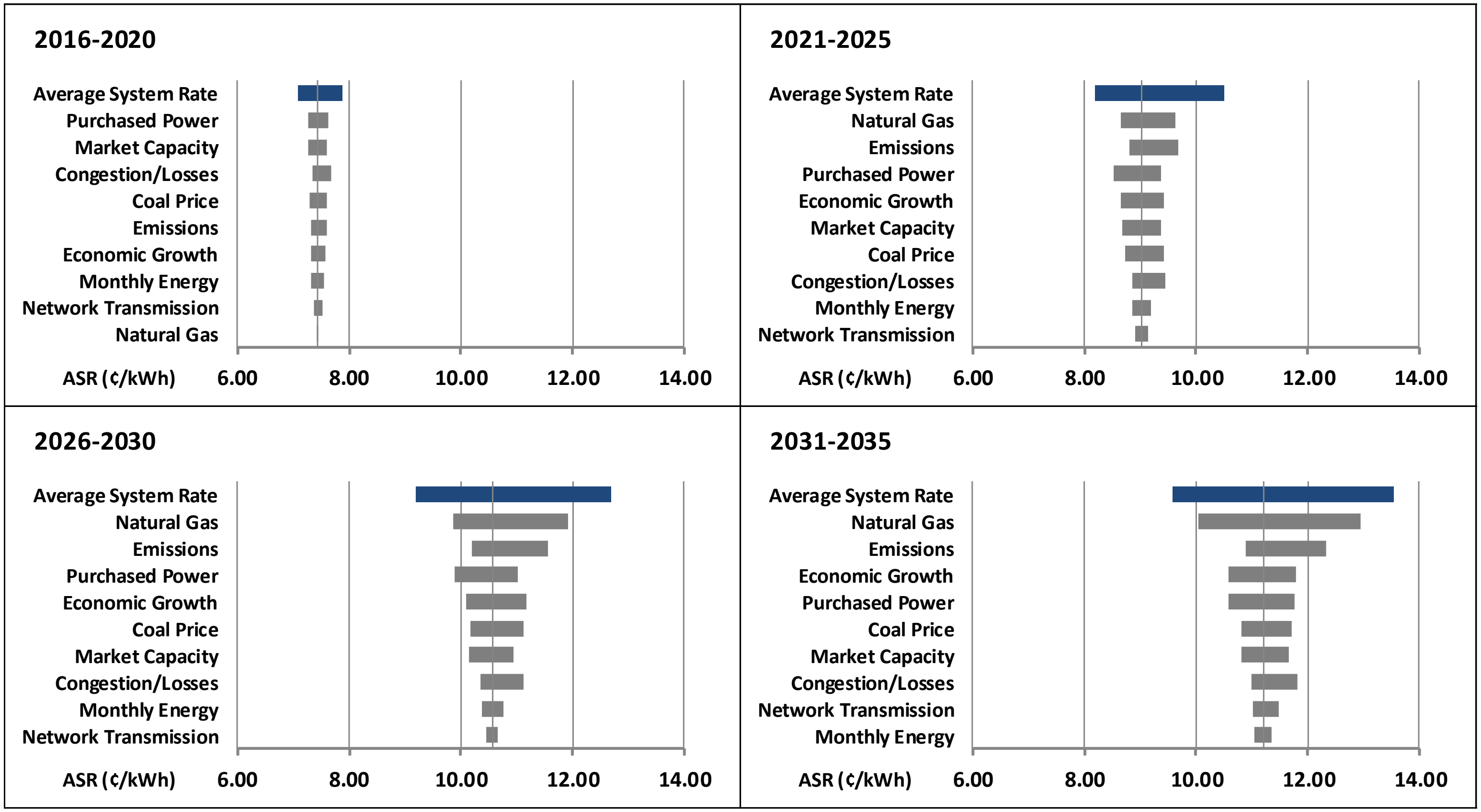
Figure 100 Plan03 Risk Profile



Source: IMPA

Tornado Chart Observations: The following tornado charts summarize the stochastic results in five year blocks. 2016-2020 remains fairly stable as in the other Plans. In the next three charts, the exposure due to CO_2 uncertainty is noticeable; however the band is not as wide as Plan01 and Plan02. This is due to the retirement of the coal units and lower emissions from the new gas units. Going forward, CO_2, gas price and purchased power costs are the primary risk factors for IMPA's portfolio in this plan.

Figure 101 Plan03 Tornado Charts

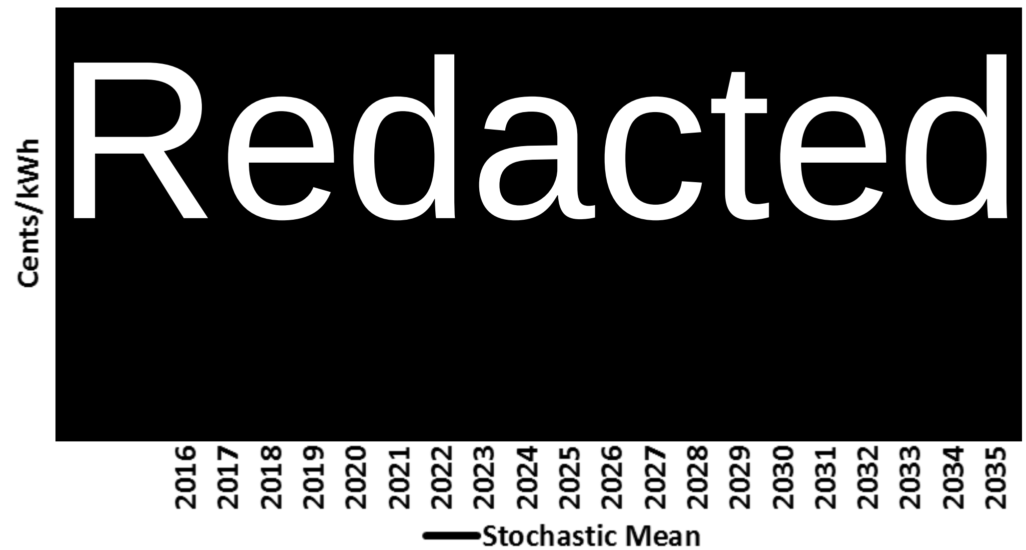


Source: IMPA

15.6 PLAN04 RESULTS

Plan Summary: Plan04 is based on the Shifting Gears scenario. In this optimization, Gibson #5 (156 MW) is retired, a combined cycle unit is added in 2021 (100 MW), combustion turbine units are added in 2025 (185 MW) and 2034 (185 MW), wind (185 MW) is added in addition to the currently planned 50 MW of solar and 218 MW of energy efficiency is added in this plan.

	Plan04
Economic Growth	Med-Low
Capital Construction Cost	Med-High
Load Forecast	Med-Low
Load Factor	3% Lower
Natural Gas Prices	Med-High
Coal Price	Med-Low
CO_2 Policy	CO_2 Tax
Reserve Margin	Pool + 2%
Retirements – MW	(156)
Natural Gas Additions – MW	470
Renewables – MW	235
Energy Efficiency – MW	218

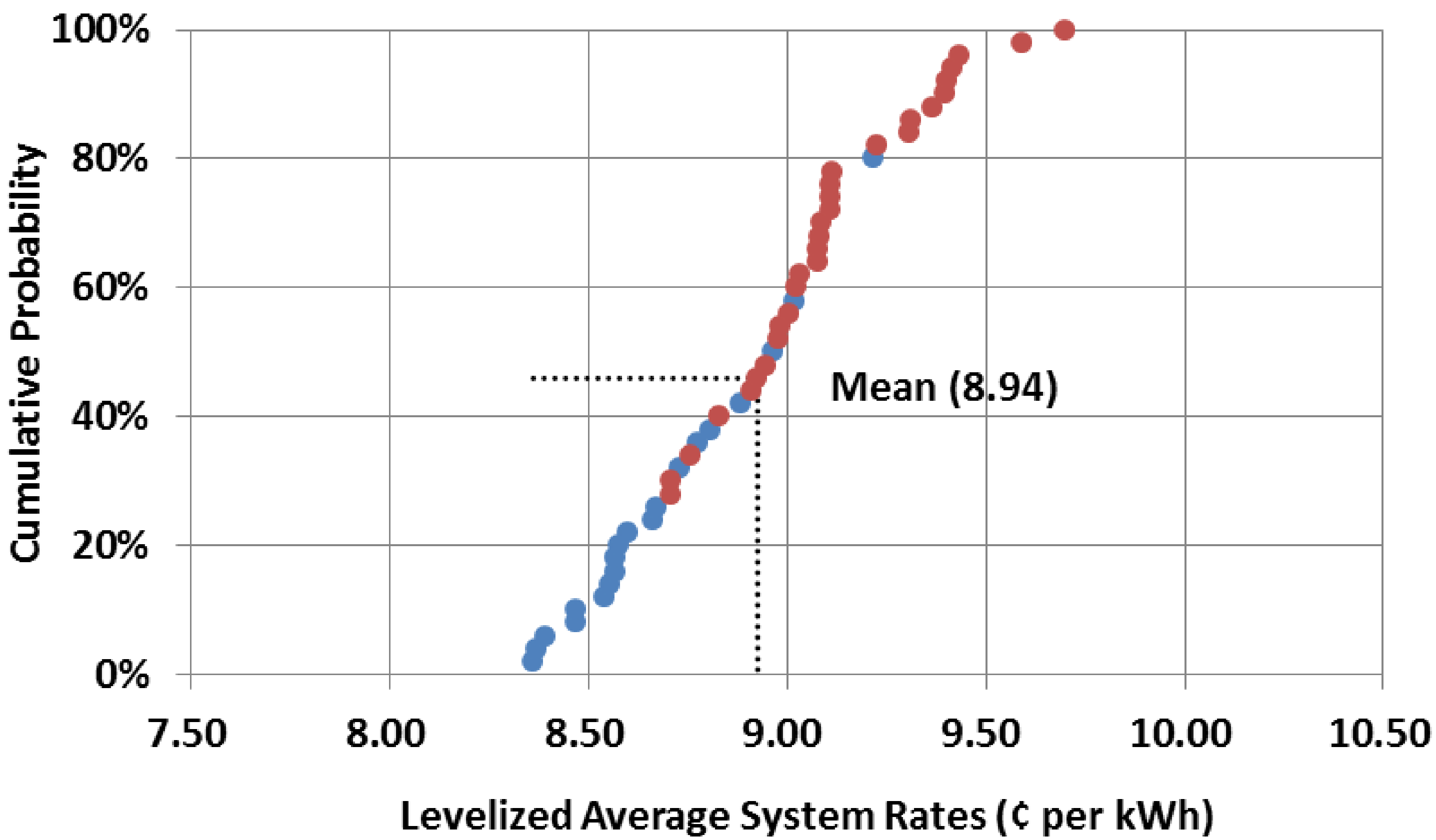


Source: IMPA

Plan Observations: Plan04 is designed to meet the EPA CPP rules via a carbon tax with 70% of the collected tax rebated to the residential consumers. Since all CO_2 emissions are taxed, CEM added wind and energy efficiency to avoid the tax. A 100 MW CC is built and there is a single coal retirement (Gibson #5). CTs are added for capacity coverage. WWVS survived retirement as it is generally used for peaking purposes. One of the biggest assumptions of this plan is the rebate level of 70%. It is quite possible little if any of the collected tax would be rebated and would instead be added to the federal coffers.

Risk Profile Observations: Sorting the 20 year levelized costs from the stochastic results produces the cumulative probability graph shown below. The line markers are divided into carbon (red) and non-carbon (blue) stochastic endpoints. The mean levelized average system rate of this plan is 8.94 cents per kWh.

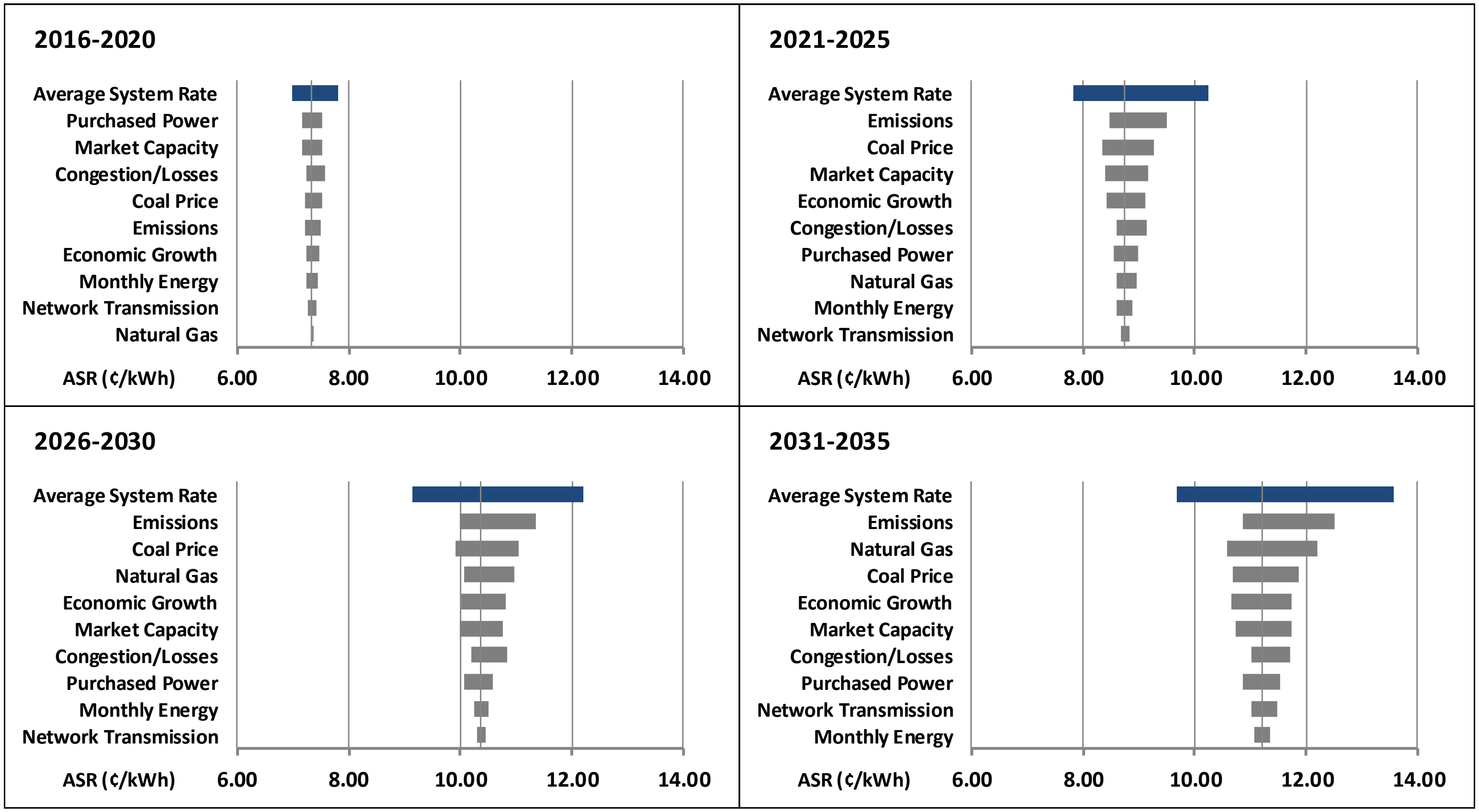
Figure 102 Plan04 Risk Profile



Source: IMPA

Tornado Chart Observations: The following tornado charts summarize the stochastic results in five year blocks. 2016-2020 remains fairly stable as in the other Plans. In the next three charts, the exposure due to CO_2 uncertainty is noticeable. The bands are not as wide as Plan01 and Plan 02, but wider than Plan03. This represents the retirement of a single coal unit in lieu of the three retired in Plan03. Going forward, CO_2, gas price and coal price are the primary risk factors for IMPA's portfolio in this plan.

Figure 103 Plan04 Tornado Charts

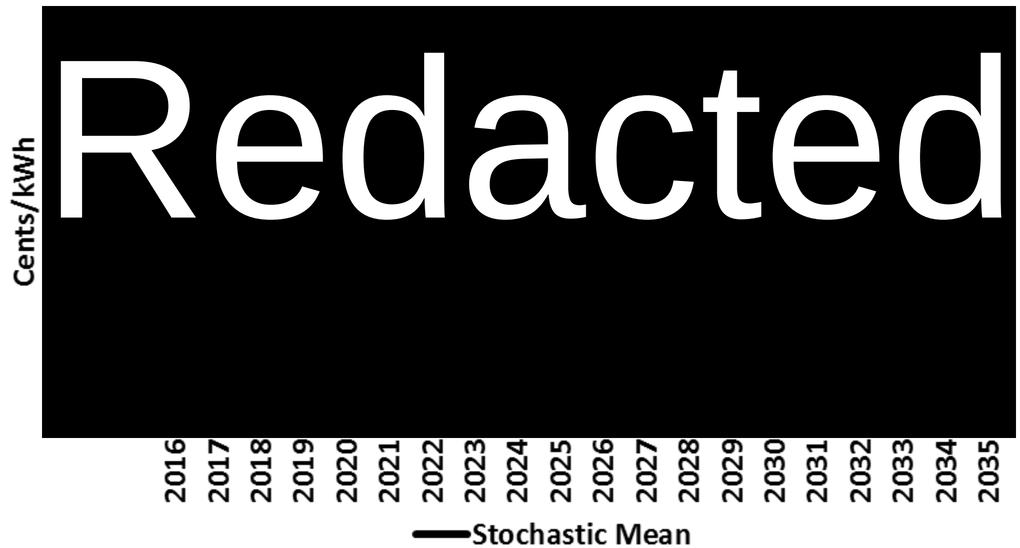


Source: IMPA

15.7 PLAN05 RESULTS

Plan Summary: Plan05 is based on the Green Revolution scenario. In this optimization, Whitewater Valley Station (90 MW), Gibson #5 (156 MW) and Trimble County #1 (66 MW) are retired. A combined cycle unit is added in 2034 (200 MW). A combustion turbine is added in 2021 (185 MW). 377 MW of wind is added in addition to the currently planned 50 MW of solar. 186 MW of energy efficiency is added in this plan.

	Plan05
Economic Growth	Low
Capital Construction Cost	High
Load Forecast	Low
Load Factor	3% Higher
Natural Gas Prices	High
Coal Price	High
CO_2 Policy	Rate-Based
Reserve Margin	Pool + 3%
Retirements – MW	(312)
Natural Gas Additions – MW	385
Renewables – MW	427
Energy Efficiency – MW	186

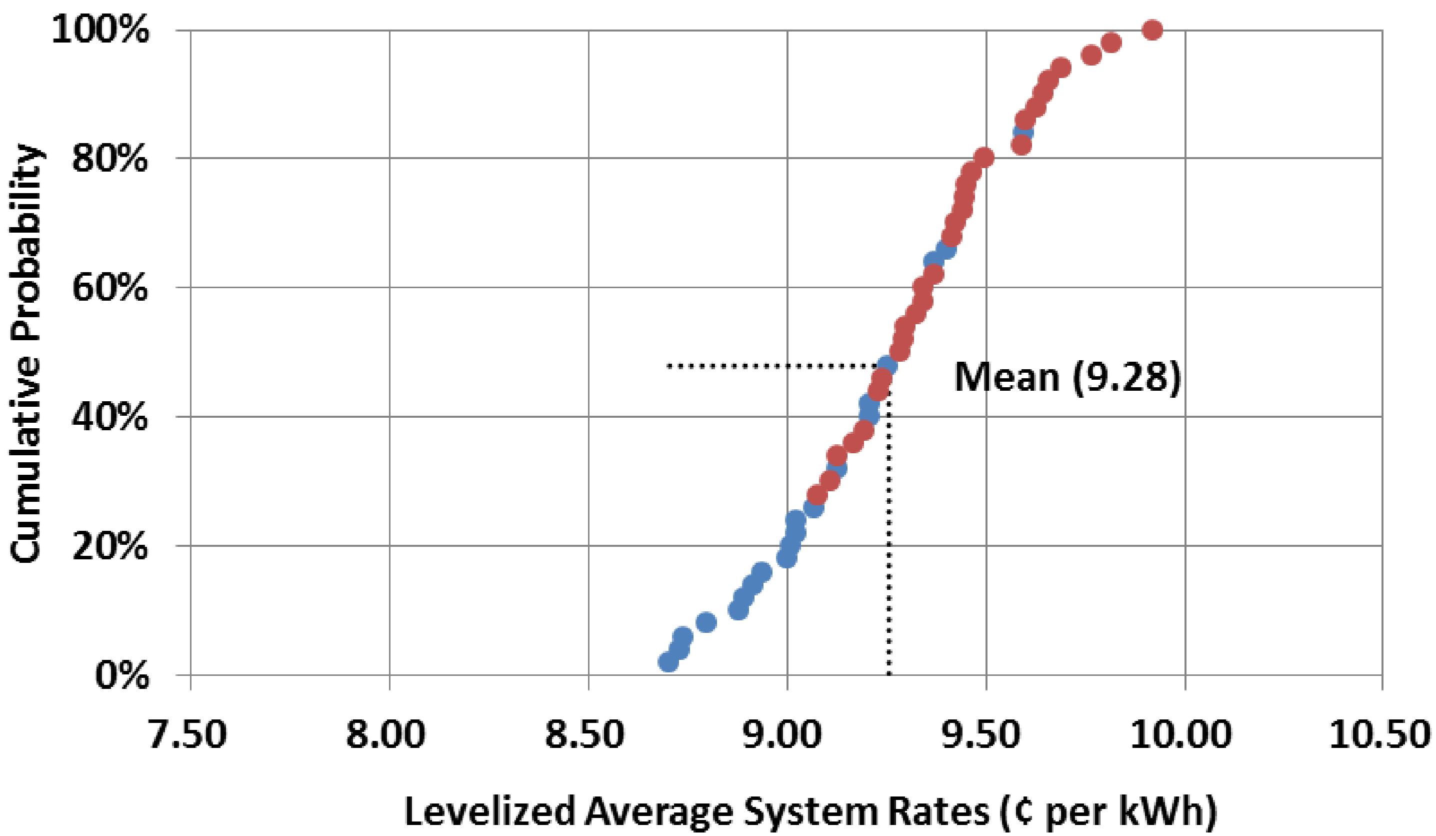


Source: IMPA

Plan Observations: Plan05 is designed to meet the EPA CPP rules through a rated-based approach. Given the design of the rate-based approach is to increase the denominator of the rate formula with ERCs, the optimization adds a significant amount of wind to the portfolio.

Risk Profile Observations: Sorting the 20 year levelized costs from the stochastic results produces the cumulative probability graph shown below. The line markers are divided into carbon (red) and non-carbon (blue) stochastic endpoints. The mean levelized average system rate of this plan is 9.28 cents per kWh.

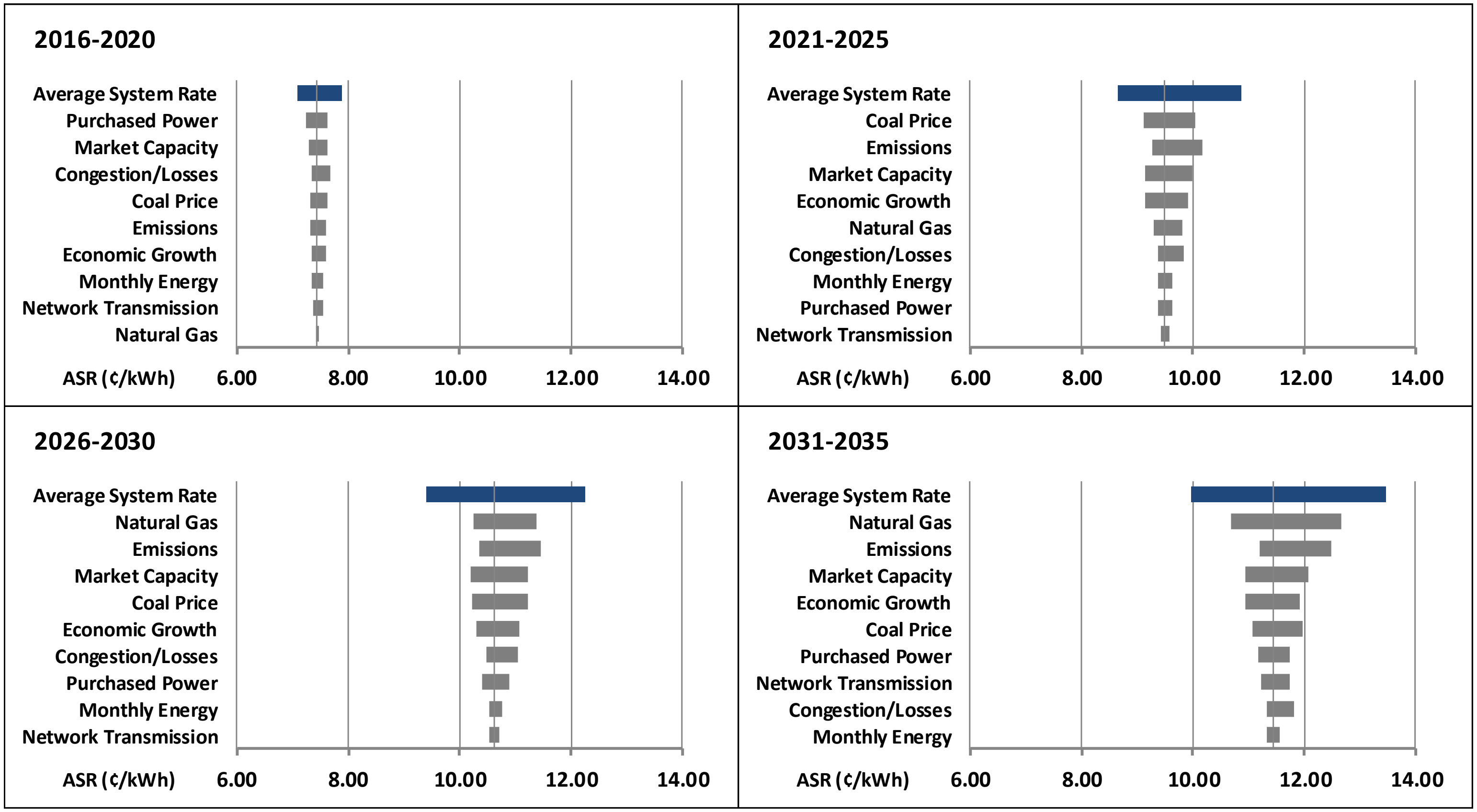
Figure 104 Plan05 Risk Profile



Source: IMPA

Tornado Chart Observations: The following tornado charts summarize the stochastic results in five year blocks. 2016-2020 remains fairly stable as in the other Plans. In the next three charts, the exposure due to CO_2 uncertainty is noticeable. The CO_2 exposure in this plan is the lowest of the all of the plans due to the coal retirements and installation of wind. Since it was optimized to a lower load, this plan leaves more exposure to market capacity price movements. In this plan, CO_2, gas price and market capacity costs are the primary risk factors for IMPA's portfolio.

Figure 105 Plan05 Tornado Charts



Source: IMPA

15.8 PLAN SUMMARY RESULTS

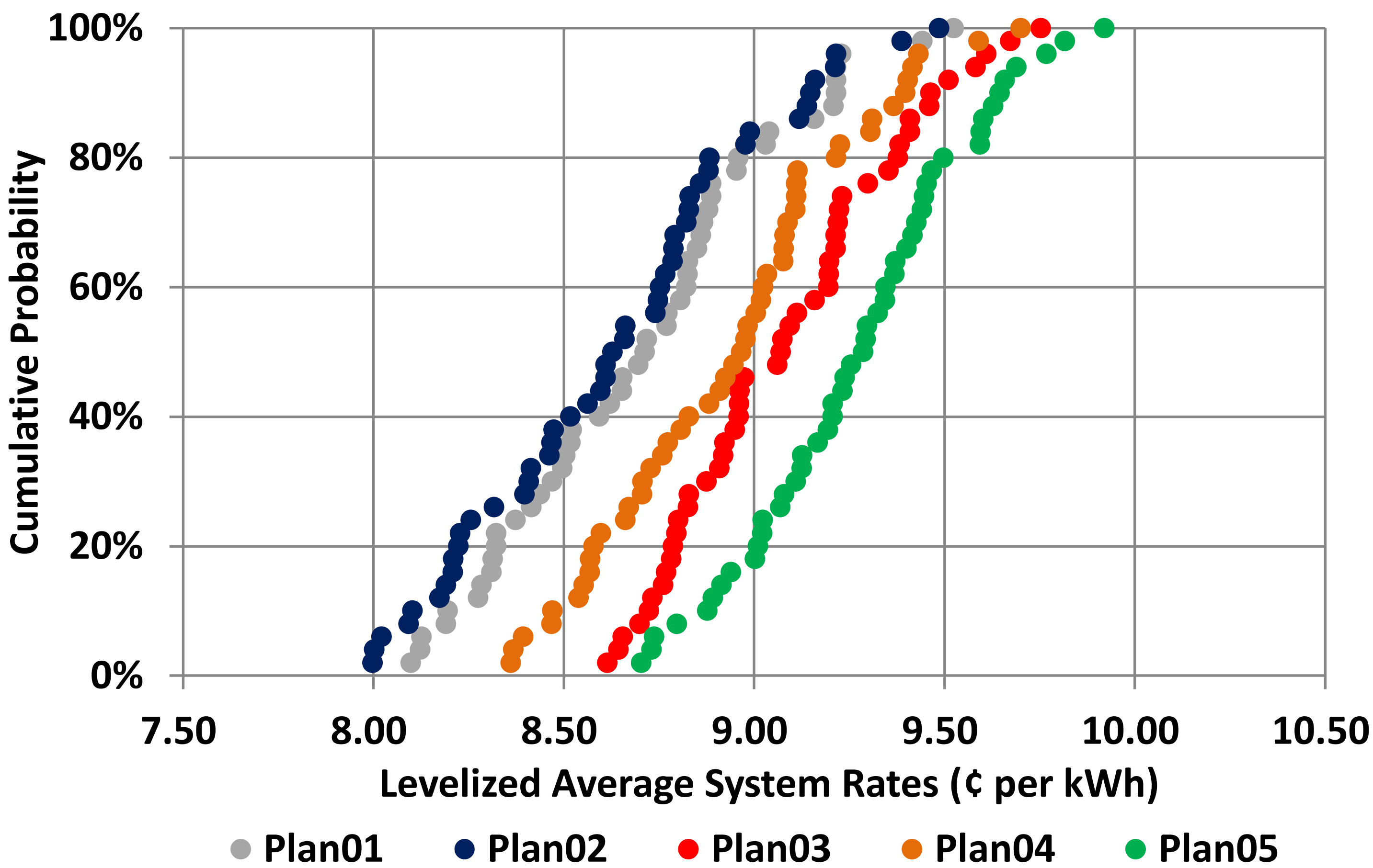
Stochastic Mean Comparison: The stochastic mean (average of 50 draws) for each plan is shown below. The plans (03, 04, and 05) which are optimized for a carbon limit future do not fare as well as the plans (01 and 02) which are optimized for a non-carbon limit future. The heavy investment in wind and energy efficiency translates into significant rate increases.

Figure 106 All Plans - Stochastic Mean Comparison

Source: IMPA

Risk Profile Comparison: The risk profile for each plan is shown below. As with the stochastic mean comparison, plans (03, 04, and 05) which are optimized for a carbon limit future do not fare as well as the plans (01 and 02) which are optimized for a non-carbon limit future.

Figure 107 All Plans - Risk Profile Comparison



Source: IMPA

INTEGRATED RESOURCE PLAN 2015

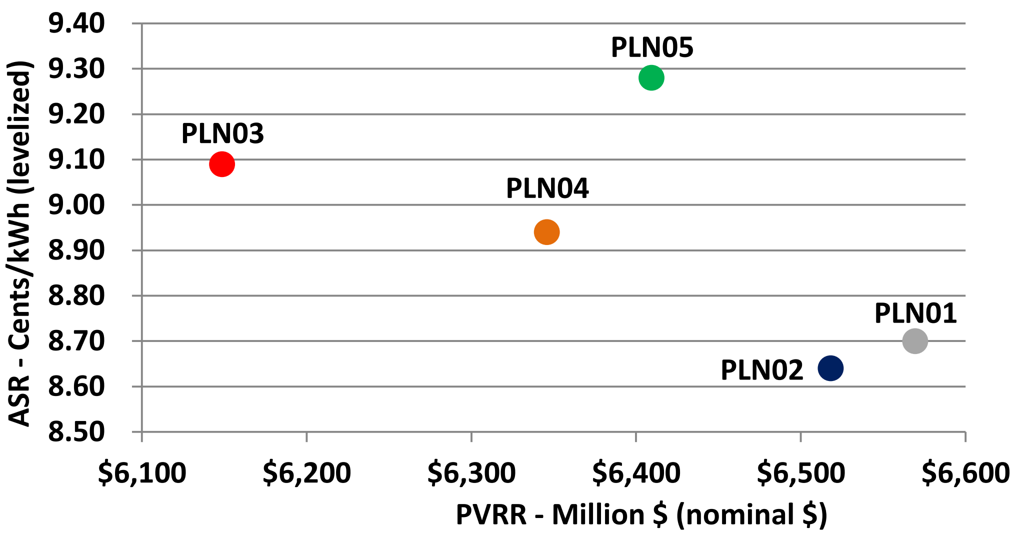
15.9 Other Evaluation Techniques

IMPA utilizes other techniques to compare the results of the five plans. These techniques are highlighted in the following sections.

15.9.1 Trade-Off Diagram

A trade-off diagram plots the PVRR on the x-axis and the ASR on the y-axis for each plan. Generally, the lower-left quadrant of this diagram would be the preferred area because that means PVRR and ASR are both minimized. The upper-right quadrant is the least desirable as neither PVRR nor ASR is minimized

Figure 108 Trade-Off Diagram

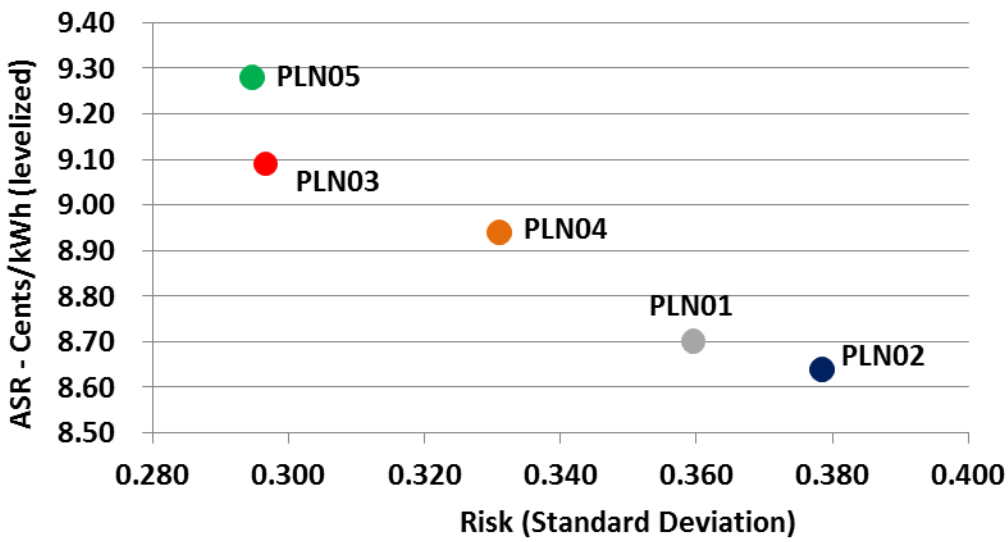


Source: IMPA

15.9.2 ASR Efficient Frontier

An efficient frontier diagram plots the standard deviation on the x-axis and the ASR on the y-axis for each plan. The standard deviation of ASR is a measure of risk of the plan. Generally, the lower-left quadrant of this diagram is the preferred area as that area has the lowest risk and the lowest ASR. The upper-right quadrant is the least desirable as it has the highest risk and highest ASR.

Figure 109 ASR Efficient Frontier

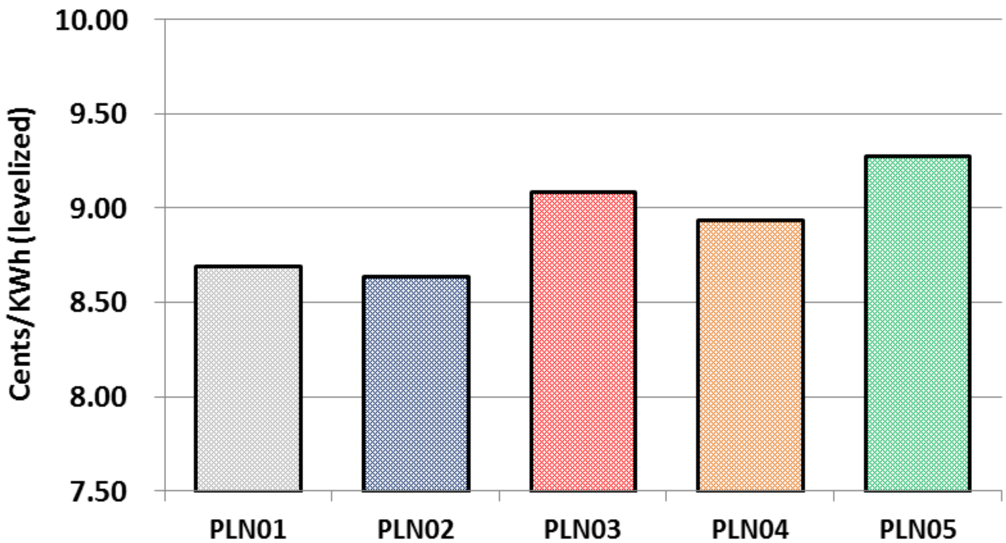


Source: IMPA

15.9.3 Average System Rates

The following chart shows IMPA's levelized ASR for the five plans. The levelized rate is the mean value of the 50 stochastic draws. In this analysis, the plans which are optimized for a carbon limit future (Plans 03-05) fare worse than plans which are optimized for a non-carbon limit future (Plans 01-02). This is due to the fact that the optimization model (CEM) objective function is to minimize PVRR, not ASR.

Figure 110 Average System Rates Chart

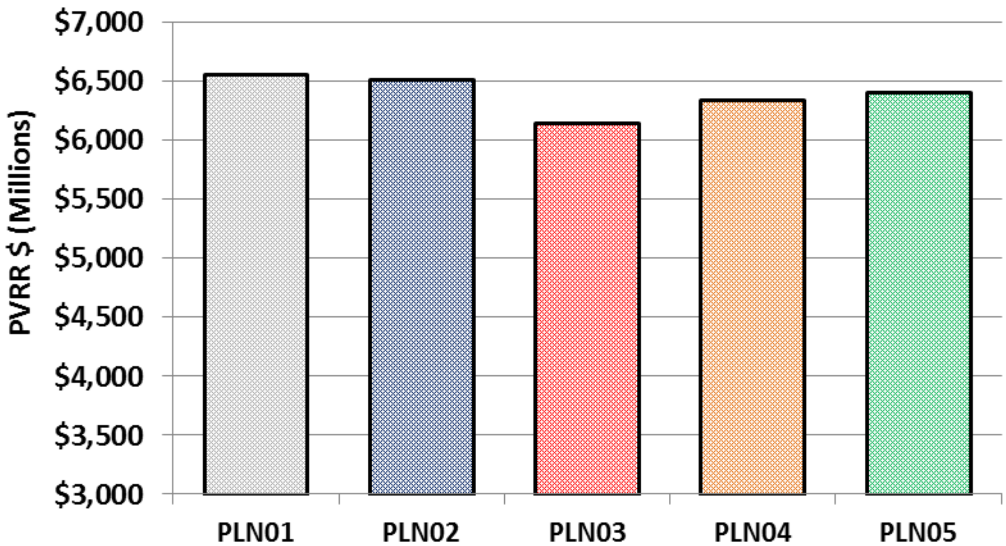


Source: IMPA

15.9.4 Present Value Revenue Requirements

The following chart shows IMPA's levelized PVRR for the five plans. The levelized value is the mean value of the 50 stochastic draws. In this analysis, the plans which are optimized for a carbon limit future (Plans 03-05) fare better than plans which are optimized for a non-carbon limit future (Plans 01-02). Plans 03-05 invest heavily in energy efficiency which leads to load destruction and lower revenue requirements.

Figure 111 Present Value Revenue Requirements Chart

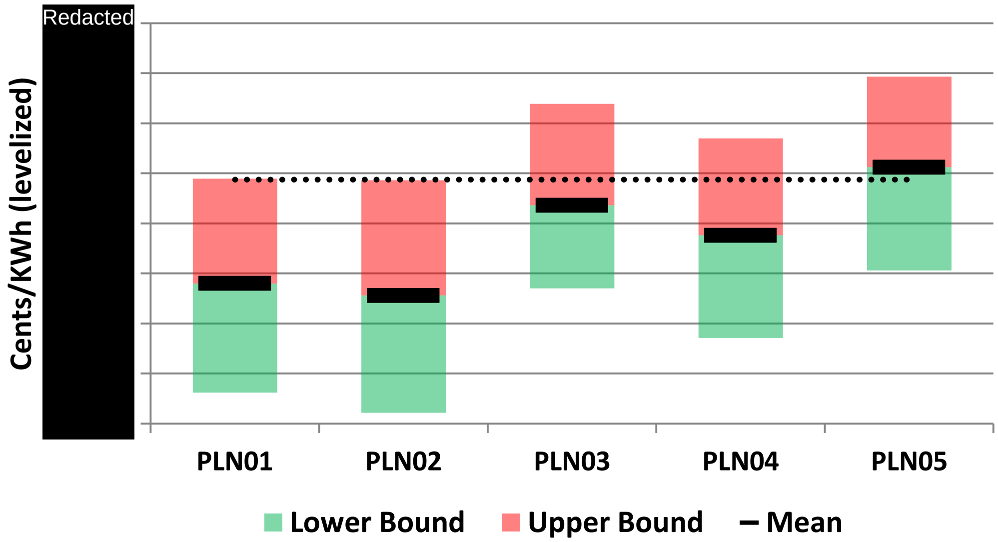


Source: IMPA

15.9.5 ASR Risk Confidence Bands

The following chart identifies the risk confidence band (5% - 95%) of each plan where the green bar represents good outcomes relative to the mean and the red bar represents bad outcomes relative to the mean. In this analysis, the plans which are optimized for a carbon limit future (Plans 03-05) have a higher mean value but a tighter confidence band than plans which are optimized for a non-carbon limit future (Plans 01-02).

Figure 112 ASR Risk Confidence Bands Chart



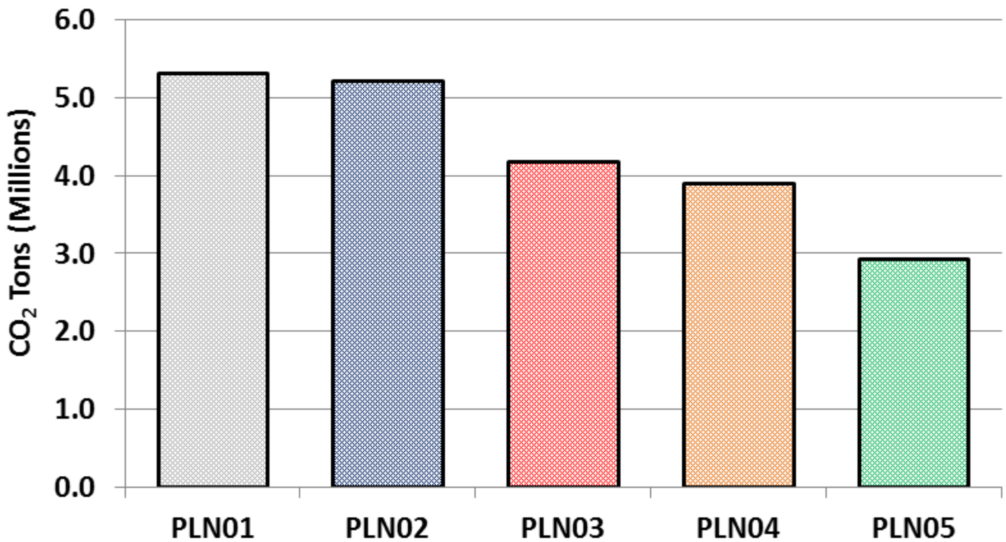
Source: IMPA

While Plans 01 and 02 have higher overall spreads between the 5th and 95th and thus more overall "risk", the 95th percentile values of these two plans compare very favorably to the other three plans. The 95th percentile value of Plans 01 and 02 (~9.20 Cents/kWh) would be the 66th, 80th and 40th percentiles for Plans 03, 04 and 05, respectively.

15.9.6 CO_2 Emissions - 2030

The following chart shows the tons (millions) of CO_2 emissions (stochastic mean) of each plan in 2030. In this analysis, Plan05, which is optimized for a rate-based carbon limit future, has the lowest CO_2 emissions. Plan01 and Plan02 which are optimized for a non-carbon limit future have the highest CO_2 emissions.

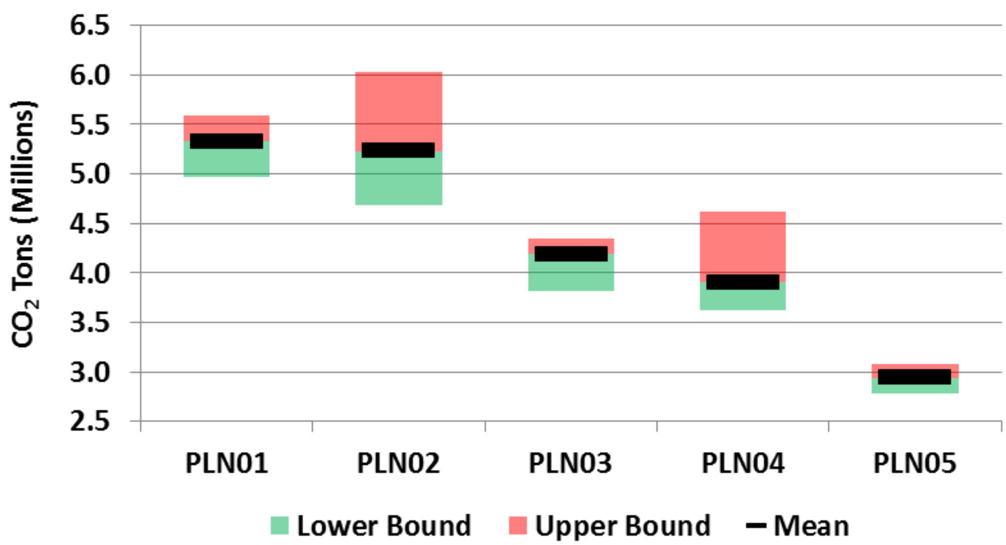
Figure 113 2030 Average CO_2 Emissions (Tons - millions)



Source: IMPA

The following chart plots the 2030 CO_2 emission range (5% - 95%) for each plan. In this analysis, Plan02 and Plan04 have the highest uncertainty bands. While they were all optimized for a carbon limited future, Plan04 has a higher uncertainty band than Plans 03 and 05 because Plan04 retires less coal generation.

Figure 114 2030 Range of CO_2 Emissions (Tons - millions)

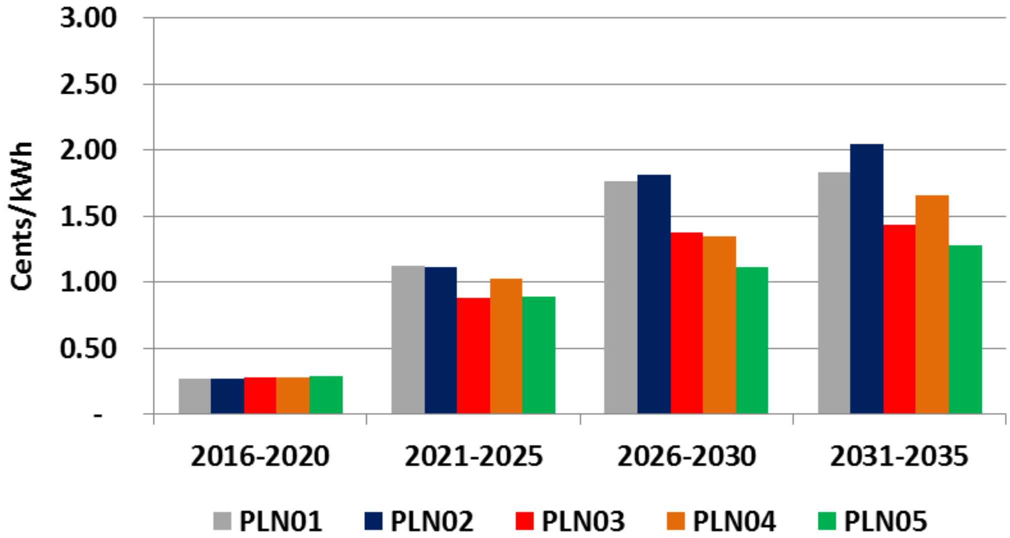


Source: IMPA

15.9.7 CO_2 Emissions Driver

From the Tornado Charts shown earlier in this section, IMPA isolated and compared the relative strength of the CO_2 emission price on the levelized average system rate. The chart is divided into the same "time buckets" as were shown in the tornado charts. Not surprisingly, Plans 01-02, which were optimized for a non-carbon limit future have the highest range of uncertainty due to the CO_2 emissions price driver.

Figure 115 Relative Strength of CO_2 Emissions Driver

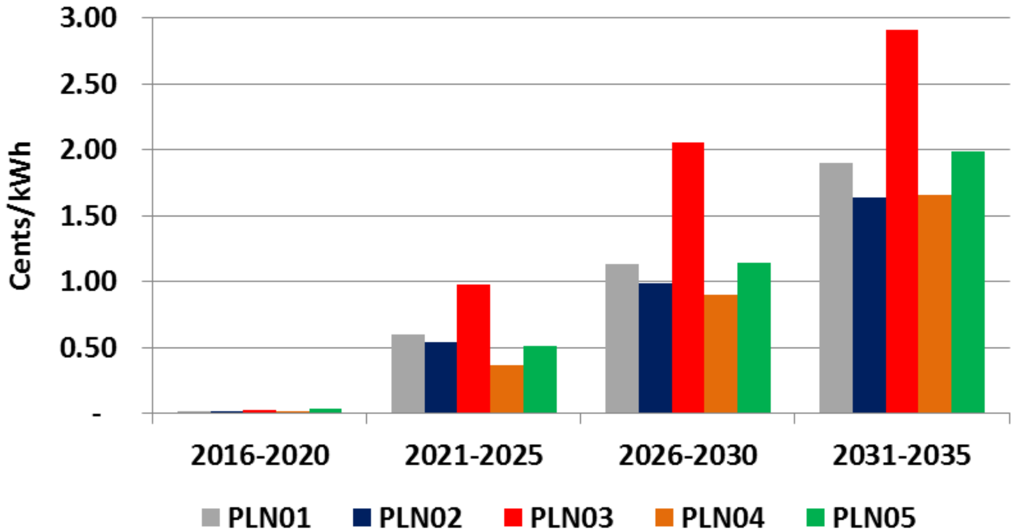


Source: IMPA

15.9.8 Natural Gas Driver

From the Tornado Charts shown earlier in this section, IMPA isolated and compared the relative strength of the natural gas price on the levelized average system rate. The chart is divided into the same "time buckets" as were shown in the tornado charts. Plan03, which adds the most natural gas combined cycle generation, has the highest range of uncertainty due to the natural gas price driver.

Figure 116 Relative Strength of Natural Gas Driver



Source: IMPA

16 PLAN SELECTION

16.1 Plan Selection

As shown throughout this report, due to pending contract expirations, IMPA is losing approximately 200 MW of capacity in the next 5 years.

The following tables show IMPA's load and capacity balance assuming no new resources are added in the future, compared to Plan01 which adds resource to meet IMPA's reserve margin requirements.

Table 15 Capacity Balance – Before Additions

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Requirements																				
Peak Load w/ EE	1,172	1,177	1,181	1,184	1,189	1,193	1,199	1,204	1,209	1,214	1,220	1,225	1,230	1,236	1,242	1,248	1,254	1,260	1,266	1,272
Resources																				
Gibson #5	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Trimble County #1	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Trimble County #2	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Prairie State #1	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Prairie State #2	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Anderson #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
Georgetown #2	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Georgetown #3	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Richmond #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Richmond #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
AEP Cost Based	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	-	-
Whitewater Valley #1	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Whitewater Valley #2	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Duke Cost Based	50	100	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duke CB - New Members	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Member Capacity	19	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Market Capacity	100	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Renewable	9	9	9	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8	8	8
Total Resources	1,364	1,369	1,279	1,279	1,279	1,179	1,179	1,179	1,179	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	988	988
Reserves	192	192	98	95	90	-14	-20	-25	-30	-36	-42	-47	-52	-58	-64	-70	-76	-82	-278	-284
Reserve Margin	16%	16%	8%	8%	8%	-1%	-2%	-2%	-2%	-3%	-3%	-4%	-4%	-5%	-5%	-6%	-6%	-7%	-22%	-22%

Source: IMPA

Table 16 Capacity Balance – After Additions (Plan01)

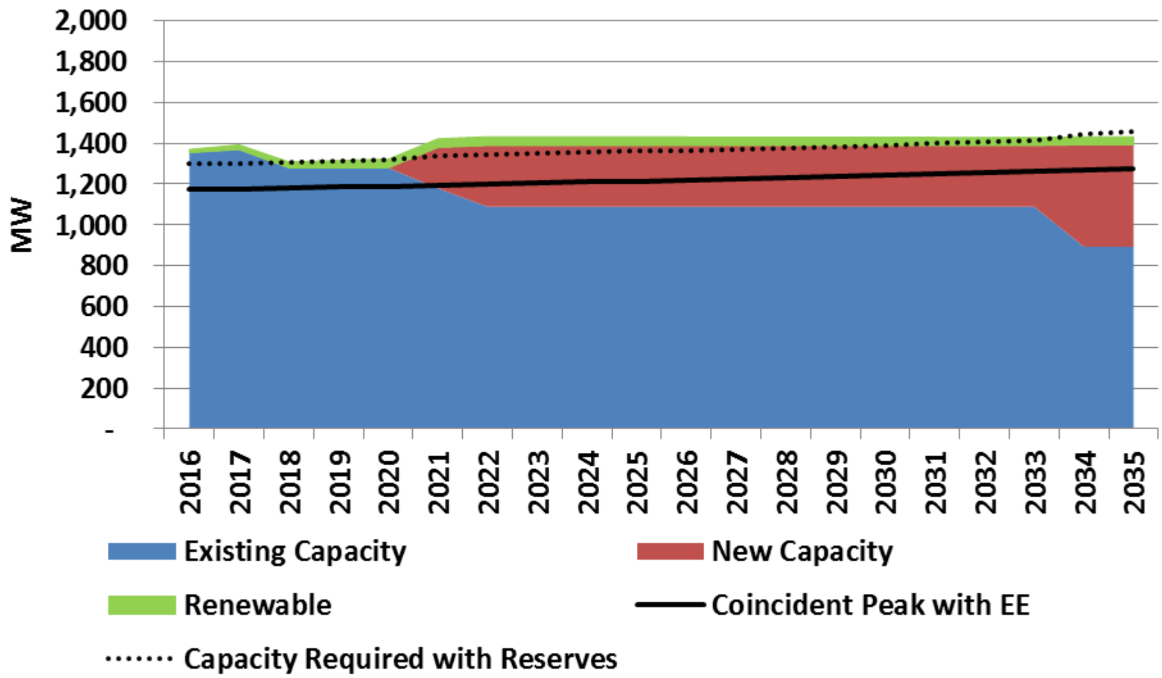
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Requirements																				
Peak Load w/ EE	1,172	1,177	1,181	1,184	1189	1,193	1,199	1,204	1,209	1,214	1,220	1,225	1,230	1,236	1,242	1,248	1,254	1,260	1,266	1,272
Resources																				
Gibson #5	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Trimble County #1	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Trimble County #2	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Prairie State #1	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Prairie State #2	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Anderson #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
Georgetown #2	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Georgetown #3	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Richmond #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Richmond #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
AEP Cost Based	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	-	-
Whitewater Valley #1	30	30	30	30	30	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Whitewater Valley #2	60	60	60	60	60	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duke Cost Based	50	100	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duke CB - New Members	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Member Capacity	19	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Market Capacity	100	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas	-	-	-	-	-	200	300	300	300	300	300	300	300	300	300	300	300	300	500	500
New Renewable	16	23	30	37	43	43	43	42	42	42	41	41	41	41	40	40	40	39	39	39
Total Resources	1,371	1,383	1,300	1,307	1,313	1,413	1,423	1,422	1,422	1,422	1,421	1,421	1,421	1,421	1,420	1,420	1,420	1,419	1,429	1,429
Reserves	199	206	119	123	124	220	224	218	213	208	201	196	191	185	178	172	166	159	163	157
Reserve Margin	17%	18%	10%	10%	10%	18	19%	18%	18%	17%	16%	16%	16%	15%	14%	14%	13%	13%	13%	12%

Source: IMPA

The following table shows IMPA's load and capacity balance assuming Plan01 new resources are added in the future.

IMPA's existing short position and future additions are graphically represented in the following figure.

Figure 117 Load/Capacity Balance Graph– Plan01



Source: IMPA

16.2 Risks and Uncertainties

As discussed elsewhere in this report, there are many uncertainties facing the electric power industry over the next decades. The following factors are just some of many that could greatly change the future of IMPA, Indiana and the nation:

- CO_2 legislation
- Generation retirements due to known EPA regulations
- New and unknown EPA regulations
- Shale gas/LNG export
- State or Federal renewable mandates
- Global and National economic conditions

IMPA's stochastic analysis, discussed in detail in section 14, attempted to incorporate many of these risks and uncertainties. The tornado charts for all plans clearly show that the single biggest risk driver for IMPA is CO_2 legislation, followed by various commodities. IMPA believes that by continuing its long held corporate concept of resource diversity, the plan herein is able to weather these potential uncertainties. The key is that there is flexibility in the plan. By embarking on the process discussed above, IMPA can select the best option among those listed and still leave itself the flexibility to react to changes in political and market conditions.

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17 SHORT TERM ACTION PLAN

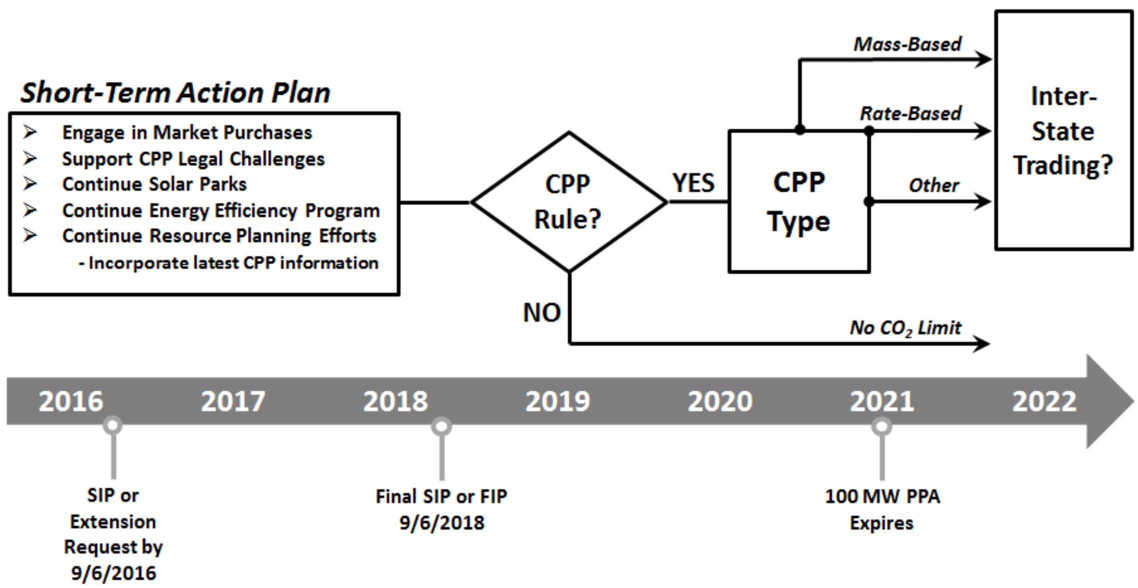
17.1 ACTION(S) REQUIRED TO IMPLEMENT THE PLAN

While IMPA has a need for capacity and energy over the next 5 years (2016-2020); those needs will be fulfilled through market purchases as the positions are relatively small. IMPA's next resource decision comes in 2021 when a 100 MW PPA expires. IMPA's Status Quo Plan (Plan01) calls for a 500 MW participation share in combined cycle unit(s) coupled with the retirement of WWVS #1 and #2. In the development of Plan01, it was assumed the EPA CPP is not implemented as it is neither known nor measureable at this point in time.

IMPA developed three additional plans (Plan03, Plan04, and Plan05) to address the impact of the carbon emission limits set forth in the CPP rule. IMPA's action plan is to delay, to the extent practical, its next resource decision to allow time for more clarity on the CPP rule. IMPA understands it ultimately may need to make its next resource decision with the best information it has at the time as the CPP legal challenge may take years to settle and will likely reach the U.S. Supreme Court. As a CPP hedge, IMPA's strategic plan is to continue its Solar Park installation program where 10 MW of solar is added to IMPA member distribution systems annually.

The following diagram illustrates the Plan Pursuit strategy:

Figure 118 Plan Pursuit Strategy (2016-2022)



As shown in the diagram above, even if the CPP rule is upheld, there are a number of questions to be answered, which will affect IMPA's next resource decision. Is the CPP massed-based, rate-based or something else? IMPA has generation in Indiana, Illinois, and Kentucky. Will the states have similar plans which allow inter-state trading or will each state be unique? How do natural gas, energy efficiency and renewables fit into the mix?

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18 IRP GUIDELINES (170 IAC 4-7)

18.1 INDEX OF RULES AND REPORT LOCATION REFERENCE

Current Rule

170 IAC 4-7 Reference	Description	Reference
4.1	External data sources	Section 9.3 Appendix E Appendix F
4.2-4.6	Load Forecasting Matters	Section 4.2 Section 5 Appendix D
4.7-4.9	Miscellaneous planning criteria and practices	Section 3.3 Section 4.3 Section 7.1
4.10-4.15	Transmission Matters	Section 4.5 Section 8.1 Appendix H
4.16	Explanation of avoided cost calculation	Appendix G
4.17	Hourly System Demand of the most recent historical year	Appendix A
4.18	Description of public participation procedure, if used.	IMPA solicits input from the IMPA Board of Commissioners when developing scenarios. IMPA's IRP is presented to the Board on two occasions with formal approval taking place after initial Board input and a second presentation.
5	Analysis of historical and forecasted levels of peak demand. Forecast scenarios.	Section 4.2 Section 5 Appendix B
6	Resource Assessment	Section 4 Section 6 Section 7 Appendix E Appendix F Appendix G
7	Selection of Future Resources	Section 6 Section 7 Section 13 Section 15

8	Resource Integration	Section 15 Section 16
9	Short-term Action Plan	Section 17

Proposed Rule (New Rule References)

4(a)	IRP Summary Document	Appendix J
4(b)10	Miscellaneous Transmission	N/A Section4.5 Appendix H
4(b)11	Contemporary Methods, Model Selection and Description	Sections 9-15
6(a)	Continued use of existing resource as a new resource alternative	Sections 6.1 & 13.1
8(a)	Candidate portfolios	Section 13.4
8(b)	Demonstrate how preferred resource portfolio balances cost-effective minimization with effective risk and uncertainty reduction.	Section 15 Section 16

19 APPENDIX

A. Hourly System Loads
B. Historic System Load Shapes
C. C1 - Hourly Market Prices – Indiana Hub
   C2 - Hourly Market Prices – AD Hub
D. IMPA Load Forecast
E. E1 - Existing Resource Data – Summary
   E2 - Existing Resource Data – Detailed
F. Expansion Resource Data
G. Avoided Costs
H. Statement on FERC Form 715
I. I1 - 2012 IMPA Annual Report
   I2 - 2012 IMPA Annual Report - Financials
J. IRP Summary Document

Q 7.1: Please refer to Richmond Power & Light's response to OUCC DR 2.1, Attachment DR 2.1-1. On line 16, two versions of the Handy-Witman [sic] Index are mentioned, 2017 and 2018. Please provide copies of each of these documents as well as the most recent version available.

Response: In addition to the General Objections above, RP&L objects to the extent that this response requires RP&L or NewGen to violate federal copyright protection. RP&L also notes that this data from the Handy-Whitman Index was never in possession of RP&L as a government entity subject to public records laws, and thus it was not already in the public domain. Subject to these objections and the provisions of the Non-Disclosure Agreement between the OUCC and RP&L, Petitioner responds as follows:

Please see Confidential Attachment 7.1 for the Handy-Whitman index "Cost Trends for Utility Construction—North Central Region", which is a copyrighted service subscribed to by NewGen Strategies & Solutions, and is therefore being provided under the Non-Disclosure Agreement with the OUCC. Ms. Tomczyk highlighted the data she used on this Excel spreadsheet, which is Line 1 ("Total Plant--All Steam Generation"), Columns EW, EZ, FF, FM, FO, FP and FR (2012-2019). There are not "two versions" of this data. When Handy-Whitman adds new data, the previous data for all the previous years stays the same. The 2017 index number is shown in Column FM and the 2018 index number in Column FP. Please also note that the remaining data in this index, which relates to other generator fuel types (nuclear, gas, etc.) have been redacted, as they were not used in Ms. Tomczyk's analysis and are thus not relevant to this response.

Q 9.3: **Referring to Witness Tomczyk's testimony where she states "WWVS's retirement date is not definitive at this time, it will likely occur in the next five to ten years." Please answer the following questions:**

a. **If WWVS is retired in five years, when will the decommissioning process begin and end?**
b. **If WWVS is retired in six years, when will the decommissioning process begin and end?**
c. **If WWVS is retired in seven years, when will the decommissioning process begin and end?**
d. **If WWVS is retired in eight years, when will the decommissioning process begin and end?**
e. **If WWVS is retired in nine years, when will the decommissioning process begin and end?**
f. **If WWVS is retired in ten years, when will the decommissioning process begin and end?**
g. **What is RP&L's best estimate as to when the decommissioning process of WWVS will begin and when it will be completed?**

Response: In addition to the General Objections listed above, RP&L objects to these questions to the extent they require RP&L to perform an analysis it has not yet performed and objects to performing. Subject to these objections, RP&L responds as follows:

As noted in Ms. Tomczyk's Direct Testimony (p. 32), RP&L has not conducted a study on decommissioning costs that likely would also include an estimate of the timing of that process. Given that RP&L lacks sufficient internal knowledge to conduct a decommissioning study on its own, this study would be performed by an independent consultant. RP&L currently lacks the funds to pay for a decommissioning study, let alone the cost of decommissioning itself; hence, why the Utility is proposing a reserve fund for this purpose. As discussed in Witness Baker's testimony, RP&L also notes that the continued operation of WWVS is impacted by the provisions of the Amended Capacity Purchase Agreement with IMPA, as well as IMPA's Integrated Resource Planning process.

Q 9.8: Is account # 92015, Salaries-Telecomm, related to labor for Parallax Systems?

Response: Account #92015 Salaries-Telecomm is an account where the salaries for Parallax employees gets charged to when payroll is processed. Parallax then reimburses RPL for all of these salaries monthly. The reason there is a balance in this account (which could be a debit or credit, depending on the month) is a timing issue. This is because the reimbursement from Parallax comes the month following when the charges are expensed to this account from payroll. Ultimately this account works like a clearing account and should be zero because Parallax incurs all salary expenses for its employees. RP&L is willing to remove any positive balance in this account from its calculation of the revenue requirement.

Q 13.4: What makes up the various "credit card charges" transactions in account no. 92600?

Response: These credit card charges include expenses for retirement gifts/celebrations, some funeral/sympathy memorials, employee wellness challenge awards, perfect attendance award, health fair, etc. As discussed in the Response below to Q 13.5, these expenditures are authorized under Richmond's Municipal Code § 52.07(h).

Q 13.5: Why are various donations, "in memory of," "flowers," "fresh arrangement/sympathy", etc. in account no. 92600 considered an employee benefit?

Response: RP&L does not consider these expenses to be an employee benefit. Richmond's Municipal Code § 52.07(h) provides that RP&L is "authorized to engage in activities and expenditures of a reasonable nature which will promote good relations with its employees, including but limited to the issuance of award plaques, the sending of flowers to employees and their families as occasions warrant, and activities of a similar nature." This Ordinance was adopted pursuant to Richmond's home rule authority to under IC 36-1-3 provide for the promotion of city business and good relations with the community and its employees. The State Board of Accounts has recognized that as long as there is an authorizing ordinance, the expense amounts are not excessive, and are properly documented and approved under normal municipal procedures for claims, they are a proper use of public funds. Please see page 5 of the SBOA's December 2015 Bulletin on the Promotion of City and Town Business:
https://www.in.gov/sboa/files/ctb2015_012.pdf

Q 17.1: On page 17, line 22 of Laurie A. Tomczyk's testimony, she states the labor expense adjustment is $254,123. In her Attachment LAT-2, page 16, line 108, the adjustment shows as $254,161. Which of these is the correct amount?

Response: The adjustment of $254,161 in Attachment LAT-2, page 16, line 108, is the correct amount.

Q 17.2: Refer to Laurie A. Tomczyk's Attachment LAT-2, pages 15-1The adjustment of $254,161 in Attachment LAT-2, page 16, line 108, is the correct amount.6, please explain how the 2020 budgets were developed for the labor, employee benefits, and FICA expenses.

Response: The employee benefits package is generally calculated at 40% of hourly pay. That package includes: health insurance, Defined Contribution Retirement Plan, vacation and holiday pay. To the extent retirements were known in advance, those were taken into account in budgeting employee salary expense. FICA expenses were calculated at standard employer contribution levels.

a. **Does RP&L plan to hire new employees in 2020? If so, please provide the number of expected new hires, the positions they will fill, and the expected salary and benefits breakdown for each.**

Response: RP&L's total employee count has fallen from 151 to about 95-97 over the last 20 years, from a high of 161 in the 1980s. Some of that attrition was due to employees at Whitewater Valley Station moving to IMPA, while others were related to cost saving measures and other efficiencies done to help keep rates low. As experienced by many other companies, RP&L's aging workforce, and the five year timeline for new apprentice lineman/substation employees to reach journeymen status, has also had an impact. The following positions are/were planned this year:

1. One Janitor (hired in March 2020 – replaces retiree) - $18.68 hr. + Benefit Package

2. One Customer Service Representative (hired March 2020 – replaces a CSR that passed away) - $21.37 hr. + Benefit Package

3. One Information Technology Technician (replaces retiree) - $22.06 hr. + Benefit Package

4. One Electrician C (replaces employee that passed away) - $24.47 hr. + Benefit Package

5. One Electronic Technician C (replaces retiree) - $26.04 hr. + Benefit Package

6. One tree trimmer (replaces retiree) - $22.97 hr. + Benefit Package

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***Indiana Office of Utility Consumer Counselor Public's Exhibit No. 5_Testimony of OUCC Witness Caleb R. Loveman*** has been served upon the following parties of record in the captioned proceeding by electronic service on, July 2, 2020.

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