Table 5-14: Benefit Cost Analysis Results – UCT

Program	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
Custom	$340,264,393	$60,474,877	$279,789,516	5.6
New Construction	$98,374,129	$18,786,751	$79,587,378	5.2
Prescriptive	$396,617,207	$38,748,919	$357,868,288	10.2
Retro-Commissioning	$16,901,754	$7,739,152	$9,162,602	2.2
Small Business Direct Install	$87,942,866	$16,596,204	$71,346,663	5.3
New Measures Prescriptive	$23,743,405	$5,029,889	$18,713,516	4.7
New Measures Custom	$9,439,944	$1,990,940	$7,449,004	4.7
New Prescriptive Ag Measures	$2,859,702	$523,495	$2,336,207	5.5
New Measures New Construction	$15,594,391	$3,778,988	$11,815,403	4.1
Total	$991,737,791	$153,669,216	$838,068,576	6.5

5.6 Future Resource Options

5.6.1 Energy Efficiency Bundles[12]

GDS converted the measure incentive costs into an equivalent annual payment spread over the life of the measure and divided the equivalent annual payment by the measure's first-year kWh savings to calculate the incentive cost per lifetime kWh saved for each measure. According to the November 2008 National Action Plan for Energy Efficiency guide titled "Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers," program administrative costs are typically not included when calculating cost effectiveness at the measure level. Based on this recommendation, program administrative costs were not included in this cost calculation. Tables 5-15 and 5-16 show the cumulative annual MWh savings, MW savings and annual utility budgets for these three bundles for the energy efficiency base case scenario for residential and C&I customers, respectively. Table 5-17 summarizes the total. The cumulative MWh and budget costs are additive for residential and C&I to arrive at the total, but the peaks are not, due to the fact that different programs are not coincident. The total bundles were used in the IRP modeling.

12 Please note, the MWh, MW and budgets utilized in the IRP were from an earlier draft of the Energy Efficiency Savings Update and may differ slightly from the numbers in the final report included in Appendix B. This was due to the timing of the final report compared to when numbers were required for the model runs. However, the differences are not significant. The tables in this section reflect the numbers utilized by CRA in the IRP modeling efforts.

Table 5-15: Residential Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	23,198	9.8	$3,120,947	27,435	6.6	$6,363,684	341	0.2	$332,842
2020	36,732	12.0	$3,118,788	55,160	13.1	$6,363,871	599	0.3	$332,467
2021	50,064	14.5	$3,115,234	82,515	19.5	$6,362,402	856	0.5	$332,085
2022	70,676	18.9	$4,169,756	86,004	20.4	$1,216,278	13,208	3.5	$15,436,140
2023	91,166	23.8	$4,300,842	89,310	22.2	$1,256,494	24,414	6.8	$15,482,175
2024	112,679	28.3	$4,429,560	93,419	23.3	$1,306,866	35,635	9.7	$15,529,778
2025	133,822	32.8	$4,569,988	96,910	24.5	$1,350,188	46,866	12.6	$15,574,511
2026	155,209	37.4	$4,699,753	100,720	25.8	$1,393,143	58,108	15.5	$15,621,458
2027	176,419	41.8	$4,836,631	104,348	26.8	$1,433,990	69,363	18.1	$15,670,403
2028	199,234	46.6	$4,970,286	108,790	28.1	$1,446,694	80,604	21.0	$15,717,871
2029	217,904	50.9	$5,106,871	112,422	29.6	$1,474,239	91,853	24.2	$15,766,369
2030	237,319	55.2	$5,247,332	116,343	31.1	$1,486,926	103,112	27.4	$15,817,541
2031	254,732	59.2	$5,394,368	119,996	32.5	$1,497,348	114,383	30.5	$15,871,633
2032	274,152	63.3	$5,544,922	124,489	34.0	$1,509,677	125,665	33.7	$15,925,409
2033	290,429	67.5	$5,698,959	127,935	35.4	$1,545,193	136,952	36.9	$15,978,312
2034	300,194	69.8	$5,823,060	104,480	30.4	$1,561,017	148,249	40.3	$16,033,291
2035	309,001	71.9	$5,952,395	80,860	25.9	$1,574,207	152,798	42.1	$16,091,088
2036	320,400	74.4	$6,099,762	57,323	22.7	$1,584,608	157,352	44.0	$16,145,518
2037	323,194	75.3	$6,198,431	58,462	23.3	$1,596,027	159,923	44.8	$16,181,313
2038	326,486	76.2	$6,299,172	59,653	23.9	$1,607,685	162,493	45.6	$16,217,860
2039	328,471	76.6	$6,402,029	60,152	24.1	$1,619,588	164,753	46.0	$16,255,174
2040	332,568	75.3	$6,507,046	60,938	18.7	$1,631,741	166,995	42.1	$16,293,272
2041	333,792	75.9	$6,614,269	61,276	19.1	$1,644,149	169,223	43.0	$16,332,170
2042	335,604	76.4	$6,723,743	61,617	19.6	$1,656,818	169,385	43.5	$16,371,885
2043	336,350	76.8	$6,835,516	61,761	20.1	$1,669,753	169,537	44.2	$16,412,433
2044	338,661	77.1	$6,949,636	62,046	20.2	$1,682,960	169,620	44.2	$16,453,834
2045	338,978	77.4	$7,066,152	62,014	20.2	$1,696,443	169,698	44.2	$16,496,103
2046	340,018	77.6	$7,185,116	62,077	20.2	$1,710,210	169,770	44.3	$16,539,261
2047	340,876	77.8	$7,306,578	62,112	20.3	$1,724,267	169,832	44.3	$16,583,324
2048	342,462	78.0	$7,430,590	62,240	20.3	$1,738,618	169,882	44.3	$16,628,313

Table 5-16: C&I Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	57,477	13.7	$7,093,091	14,523	2.9	$1,954,097	0	0.0	$0
2020	121,341	28.9	$7,881,212	30,797	6.1	$2,171,219	0	0.0	$0
2021	191,591	45.6	$8,669,334	48,518	9.7	$2,388,341	0	0.0	$0
2022	258,294	62.0	$9,025,573	67,461	13.5	$2,703,163	193	0.0	$110,756
2023	332,676	78.7	$9,252,548	86,486	17.4	$2,770,426	387	0.1	$117,760
2024	408,406	95.7	$9,484,921	102,260	20.4	$2,835,287	592	0.1	$124,773
2025	485,669	113.0	$9,752,695	116,719	23.3	$2,890,234	784	0.2	$132,546
2026	564,928	130.5	$10,033,029	131,295	26.1	$2,979,807	1,025	0.2	$150,891
2027	645,287	148.4	$10,273,287	140,436	28.0	$3,046,937	1,249	0.3	$158,013
2028	722,917	166.1	$10,524,231	149,709	29.8	$3,107,737	1,497	0.3	$166,543
2029	801,264	184.1	$10,777,543	157,031	31.3	$3,168,288	1,744	0.4	$173,742
2030	880,358	202.4	$11,027,368	164,628	32.9	$3,224,944	1,975	0.4	$180,283
2031	953,821	219.3	$11,348,675	170,945	34.2	$3,311,363	2,254	0.5	$189,145
2032	1,026,654	236.3	$11,619,566	178,316	35.6	$3,372,494	2,470	0.5	$195,882
2033	1,099,943	253.4	$11,900,715	184,506	37.0	$3,440,787	2,701	0.6	$202,895
2034	1,126,736	258.8	$12,151,635	188,173	37.8	$3,482,137	2,981	0.6	$190,921
2035	1,148,291	262.9	$12,362,496	190,812	38.4	$3,520,890	3,203	0.7	$191,340
2036	1,164,268	265.7	$12,559,119	194,251	39.0	$3,556,600	3,421	0.7	$191,791
2037	1,180,955	269.5	$12,759,892	195,605	39.4	$3,592,662	3,539	0.8	$192,274
2038	1,196,990	273.1	$12,964,294	197,155	39.7	$3,629,416	3,663	0.8	$192,769
2039	1,210,329	276.2	$13,090,516	198,060	39.9	$3,659,638	3,777	0.8	$193,188
2040	1,222,254	279.1	$13,219,389	200,104	40.2	$3,690,495	3,912	0.8	$193,616
2041	1,232,984	281.7	$13,350,967	200,623	40.4	$3,722,000	4,022	0.8	$194,052
2042	1,242,596	284.0	$13,485,309	201,428	40.6	$3,754,167	4,119	0.9	$194,498
2043	1,251,057	286.0	$13,622,472	201,699	40.7	$3,787,009	4,205	0.9	$194,953
2044	1,258,590	287.8	$13,762,516	202,762	40.8	$3,820,541	4,313	0.9	$195,418
2045	1,265,087	289.4	$13,905,500	202,854	40.9	$3,854,778	4,400	0.9	$195,892
2046	1,270,045	290.7	$14,051,487	203,301	41.0	$3,889,733	4,495	0.9	$196,377
2047	1,274,014	291.7	$14,200,540	203,681	41.0	$3,925,422	4,588	0.9	$196,871
2048	1,277,052	292.5	$14,352,723	204,442	41.1	$3,961,861	4,690	1.0	$197,376

Table 5-17: Total Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	80,676	20.5	$10,214,038	41,958	8.4	$8,317,781	341	0.2	$332,842
2020	158,073	35.8	$11,000,000	85,957	16.8	$8,535,090	599	0.3	$332,467
2021	241,655	53.2	$11,784,567	131,033	25.4	$8,750,744	856	0.5	$332,085
2022	328,971	71.9	$13,195,329	153,465	28.9	$3,919,442	13,401	3.5	$15,546,896
2023	423,842	91.1	$13,553,390	175,796	33.5	$4,026,920	24,801	6.9	$15,599,935
2024	521,084	110.3	$13,914,481	195,680	37.1	$4,142,153	36,228	9.8	$15,654,551
2025	619,491	129.9	$14,322,683	213,629	40.5	$4,240,422	47,650	12.7	$15,707,057
2026	720,137	149.7	$14,732,782	232,015	43.9	$4,372,950	59,132	15.7	$15,772,349
2027	821,705	169.6	$15,109,918	244,784	46.3	$4,480,928	70,612	18.4	$15,828,416
2028	922,151	189.7	$15,494,517	258,499	49.0	$4,554,431	82,101	21.4	$15,884,414
2029	1,019,167	209.7	$15,884,414	269,453	51.9	$4,642,527	93,596	24.5	$15,940,111
2030	1,117,676	230.0	$16,274,700	280,971	55.0	$4,711,870	105,087	27.8	$15,997,824
2031	1,208,553	248.7	$16,743,044	290,941	57.8	$4,808,711	116,638	30.9	$16,060,778
2032	1,300,805	267.6	$17,164,488	302,805	60.7	$4,882,171	128,134	34.2	$16,121,291
2033	1,390,371	286.6	$17,599,674	312,441	63.6	$4,985,981	139,653	37.5	$16,181,207
2034	1,426,931	293.0	$17,974,695	292,653	61.6	$5,043,153	151,229	40.9	$16,224,212
2035	1,457,292	298.1	$18,314,890	271,672	59.5	$5,095,098	156,000	42.7	$16,282,428
2036	1,484,668	302.1	$18,658,881	251,574	58.1	$5,141,208	160,773	44.7	$16,337,309
2037	1,504,149	306.3	$18,958,323	254,067	59.0	$5,188,689	163,461	45.5	$16,373,587
2038	1,523,475	310.3	$19,263,467	256,808	59.9	$5,237,101	166,155	46.3	$16,410,629
2039	1,538,800	313.7	$19,492,545	258,212	60.2	$5,279,226	168,530	46.8	$16,448,362
2040	1,554,823	315.6	$19,726,435	261,042	55.2	$5,322,236	170,907	42.8	$16,486,888
2041	1,566,776	318.5	$19,965,236	261,899	55.9	$5,366,150	173,245	43.8	$16,526,222
2042	1,578,200	321.0	$20,209,052	263,046	56.5	$5,410,985	17,504	44.3	$16,566,383
2043	1,587,407	323.3	$20,457,988	263,459	57.2	$5,456,763	173,742	45.0	$16,607,387
2044	1,597,250	325.2	$20,712,151	264,809	57.4	$5,503,501	173,933	45.0	$16,649,251
2045	1,604,065	326.9	$20,971,653	264,868	57.5	$5,551,221	174,098	45.1	$16,691,996
2046	1,610,063	328.3	$21,236,603	265,378	57.6	$5,599,943	174,265	45.1	$16,735,637

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2047	1,614,891	329.4	$21,507,118	265,793	57.7	$5,649,688	174,420	45.1	$16,780,196
2048	1,619,514	330.2	$21,783,313	266,682	57.8	$5,700,478	174,572	45.2	$16,825,690

5.6.2 Demand Response Program Options

Five DR options were considered, including two options for NIPSCO's Interruptible Tariff. The objective of these options is to realize demand reductions from eligible customers during the highest load hours of the summer or winter as defined by the utility. Each program type provides DR using different load reduction and incentive strategies designed to target different types of customers. From the utility perspective, load reduction events for each of the different program types can be called with different notification time. Using a mix of programs provides load reduction resources that can be called under many different conditions. Table 5-18 lists the DR programs included in this DSM Savings Update.

Table 5-18: Demand Response Program Options

DR Program Option	Eligible Customer Classes	Mechanism	Season
DLC Central Air Conditioner Cycling	Residential, Small and Medium C&I	DLC Switch for Central Cooling Equipment	Summer
DLC Space Heating	Residential, Small and Medium C&I	DLC Switch for Space Heating Equipment	Winter
DLC Water Heater Cycling	Residential, Small and Medium C&I	DLC Switch for Water Heating Equipment	Summer and Winter
Interruptible Load Tariffs	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance.	Summer
Interruptible Load Tariffs with Third Party Aggregator	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance. Typically managed as a portfolio by third party contractor.	Summer

5.6.3 Demand Response Load Reduction Assumptions

The per-customer kW electric peak load reduction, multiplied by the total number of participating customers, provides the potential demand savings estimate. Load reduction impact assumptions are based on program performance for current or past NIPSCO programs and on secondary research for new programs. The Interruptible Rider impact was sourced from actual program performance. The percentage was scaled to match current program performance. The remaining program impacts were developed by taking an average of existing/past program performance from programs in states within the region. Table 5-19 shows the per-customer load reductions used for estimating the potential, along with sources. The majority of load reductions were obtained from the 2016 MPS, with the exceptions noted in the table.

Table 5-19: Demand Response Program Load Reduction Assumptions

Sector	DR Program Option	Load Reduction	Source
Residential	DLC AC	0.972 kW	FERC 2012 Survey adjusted to IN using National Oceanic and Atmospheric Administration temperatures
	DLC Space Heating	0.62 kW	2016 MPS
	DLC Water Heating	0.9 kW	2016 MPS
Business	DLC AC	3.1 kW	2016 MPS
	DLC Space Heating	1.5 kW	PGE Brattle Group 2016 Study
	DLC Water Heating	2.7 kW	2016 MPS
	Interruptible Rider	18% of Coincident Peak Load	2016 MPS
	Third Party Aggregator	18% of Coincident Peak Load	2016 MPS

The DR options for large C&I customers included in the Savings Update are described below:

5.6.4 Interruptible Rider

As described above and under Rider 775, large commercial customers enroll directly with NIPSCO in an agreement to curtail their load during system contingencies.

5.7 Consistency between IRP and Energy Efficiency Plans

Ind. Code § 8-1-8.5-10 ("Section 10"), which became law on May 6, 2015, requires, among other things, that a utility's energy efficiency goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility is required to petition the Commission for approval of an energy efficiency plan under Section 10 beginning not later than calendar year 2017, and not less than once every three years.

To remain consistent with the requirements of Section 10, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed an update to its 2016 MPS to determine the achievable amount of savings. *See Appendix B.* NIPSCO, through the MPS and the DSM Electric Savings Update process discussed above, then conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process, NIPSCO incorporated 3 energy efficiency DSM bundles and 3 DR bundles into the model for selection as resources. As defined above, energy efficiency measures were bundled according to each measure's cost of saved energy over its measure life and the DR programs were bundled by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program.

NIPSCO allowed DSM and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in this section, three separate DSM bundles were developed by GDS for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios.

In accordance with Section 10, NIPSCO intends to request approval in 2020 of an energy efficiency plan for implementation in 2022 ("2020 Filing") that includes:

- energy efficiency goals that are (1) reasonably achievable; (2) consistent with NIPSCO's 2018 IRP, and (3) designed to achieve an optimal balance of energy resources in its service territory;
- energy efficiency programs that are (1) sponsored by an electricity supplier and (2) designed to implement energy efficiency improvements;
- program budgets;
- program costs that include (1) direct and indirect costs of energy efficiency programs, (2) costs associated with the EM&V of program results, (3) recovery of lost revenues and performance incentives. For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs; and
- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its 2020 Filing based on the energy efficiency selected by the IRP model. This may be updated depending on the results of the 2019 MPS and/or another mechanism (i.e. DSM RFP results). The DSM Action Plan will take into account the results of the IRP for implementation and evaluation of the Energy Efficiency Plan.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing an energy efficiency program. That means that the programs included in the MPS/DSM Savings Update typically change. NIPSCO uses the MPS/DSM Savings Update as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure which has historically shown little participation or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

The benefit of an Action Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency plan. The Action Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS/DSM Savings Update, IRP and Action Plan. This is the most effective way to ensure NIPSCO has an Energy Efficiency Plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the groupings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for development of the DSM RFPs and creation of the Energy Efficiency Plan allows NIPSCO to compensate for the long lead time between the completion of a market potential study and the actual implementation of a program.

That does not mean that the Energy Efficiency Plan will be without change. Until the programs are administered to the customer base and the first-hand experiences with energy efficiency occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an on-going mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing Transmission and Distribution ("T&D") resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.
- Proactively maintain and increase availability and reliability of the electric delivery system.
- Minimize capital and operating costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk-electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and ReliabilityFirst Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through participation in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MISO Transmission Expansion Plan ("MTEP"). The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that while any transmission project NIPSCO wishes to build must generally be timely submitted for planning review by MISO to ensure that there is no harm to other systems in MISO, so long as NIPSCO does not request cost sharing of the project with other MISO members, NIPSCO does not have to obtain MISO Board approval to proceed with a transmission project if NIPSCO deems it necessary. Additionally, under extenuating circumstances, NIPSCO can request expedited review of those cost-shared projects that do require MISO Board approval.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM Interconnection LLC ("PJM") transmission system are to be coordinated with NIPSCO by PJM through MISO.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM under the MISO-PJM Joint Operating Agreement.

In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based and should relieve congestion. These projects must pass the Benefit Cost Ratio test established by MISO before approval. NIPSCO participates in this effort through the MISO Market Efficiency Planning Study, and the MISO-PJM Interregional Planning Stakeholder Advisory Committee which performs a coordinated system planning study with PJM.

NIPSCO is also an active participant in the Market Efficiency Project ("MEP") planning processes in both MISO and PJM. The MEP processes focus on evaluating potential future transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for the MISO and/or PJM footprint. These planning efforts require the benefits of proposed projects to exceed the costs (usually 1.25 or greater benefit to cost ratio) before the RTOs will consider it a viable solution.

6.1.4 Market Participants

MISO has developed a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, increases in transmission rights, reduce congestion, address reliability considerations, or other market driven needs. If the Market Participant wishes to pursue these types of upgrades, they must submit their proposal to MISO, and NIPSCO and the Market Participant must negotiate payments for these upgrades as defined in the MISO tariff and corresponding Business Practice Manuals. Market Participant-Funded Projects must be filed in a timely manner with MISO for review in its transmission planning process.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development, will determine if identified transmission upgrades are identified necessary to meet the customer's development or expansion plans.

6.1.6 Transmission System Performance Assessment

In NIPSCO's 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F), Confidential Part 2 contains the regional power flow cases. The cases include solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses, and model description. Confidential Part 3 contains applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Confidential Part 5 presents the assessment practice used.

Confidential Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system. Performance assessments are conducted annually for the near-term (5 year) and long-term (10 year) planning horizons, for both peak and off-peak load conditions, assuming known or forecasted changes in generation resources and load demand. Sensitivities to baseline forecasts or assumptions may also be considered for performance analysis of the transmission system.

NIPSCO also participates in the MISO and PJM Market Efficiency Project planning processes as discussed in Section 6.1.3: Midcontinent Independent System Operator, Inc. The MISO process includes multiple future scenarios to test future sensitivities against baseline assumptions.

6.1.7 NIPSCO Transmission System Capital Projects

NIPSCO's portfolio of transmission system projects has been identified through its annual transmission system performance assessment to establish base line reliability projects. This portfolio has been expanded to include transmission projects initiated by market participants, by customer driven development projects, and to include regional transmission projects designated through the MISO MTEP planning effort, with the most recent iteration approved by the MISO Board of Directors (MTEP 17) in 2017. NIPSCO's current portfolio includes:

- Multi-Value Project 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/Duke Energy Indiana jointly-owned Sugar Creek substation
- Circuit 13812 Maple Substation upgrade
- Circuit 13854 Aetna Substation line drop upgrade
- LaGrange Substation 138kV Ring bus conversion

In addition to current portfolio, NIPSCO recently completed all transmission system projects approved by MISO (MTEP 11) as part of Multi-Value Project 12. Projects included:

- Reynolds to Burr Oak to Hiple 345kV Lines
- Reynolds to Greentown 765kV Line

6.1.8 Electric Infrastructure Modernization Plan

The Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO's 7-Year Electric TDSIC Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's 7-Year Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO considered the need to maintain a safe and reliable system. The approximate cost of the transmission portion of the TDSIC plan is $453M over the seven-year period.

6.1.9 Evolving Technologies and System Capabilities

NIPSCO Transmission Planning has provided for the installation of two variable shunt reactors ("VSRs") at the Hiple 345kV substation as part of the Multi-Value Projects. The VSRs, which will enable better and more precise control of transmission system voltage, are a relatively recent development in the industry.

6.2 Distribution System Planning

As part of the long term view, NIPSCO continues to evaluate the benefits of smart grid and distribution automation ("DA") technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure.

NIPSCO's distribution system is periodically reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[13] Distribution operating and design criteria rely on NIPSCO design maximums in accordance with Company Standards and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics that include severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems by reimbursing them for their generation output, at utility retail rates, for energy in excess of their service's base load electricity purchase from the utility. Typically this represents the aggregate excess power produced that is not utilized internally by the customer but is instead delivered into the utility's local electric system.

Feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and to help accelerate the move toward renewable energy sources. This tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects.

[13] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

NIPSCO implemented its renewable feed-n tariff in July 2011 along with its existing net metering program. These programs introduced customer-owned renewable resource based generation onto NIPSCO's electric distribution system. A relatively significant amount of renewable generation projects began coming "on line" in 2012 and that amount has continued to grow. NIPSCO's net metering and feed-in tariff generation interconnection programs provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

At the end of 2017, the renewable generation data identified 10.7 MWs associated with the net metering program and 33.4 MWs of generation associated with the feed-in Tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, PV solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Generation:

- 8.64 MWs - Solar Generation
- 1.92 MWs - Wind Generation
- 0.132 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 18.87 MWs - Solar Generation
- 0.16 MWs - Wind Generation
- 14.35 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 55 MWs of generation is interconnected to NIPSCO's distribution system.

Based on the implementation of the net metering and feed-in tariff programs, Distribution Planning has observed voltage related operating impacts on its electric system due to larger customer-owned generation. Impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources. Differences in operational characteristics, generation penetration, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time. The diverse types of customer-owned generation also have varying effects on the electric system.

NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half MW or greater rated customer owned solar fields. These swings can present challenges to maintaining appropriate service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized "cloud affect," NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 92% of rated equipment output are observed during seasonal inclement weather conditions. Significantly reduced output levels can be seen extending over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. On the other hand, large biomass fueled combustion turbines appear to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, there were experiences of random events where customer generation dropped completely off line. The impact of lost generation becomes more significant as the generation level increases since the local distribution system needs to adjust and compensate for fast change in power sources.

Based upon several years of operating data for currently installed renewable generation resources, these technologies present a recognized energy resource that can be utilized in supplementing customer electric energy needs. However, at this time, the impact on local electric distribution service infrastructure has not demonstrated to be sufficiently available or stable to be considered an adequate 24 hours a day/seven days a week/365 days a year substitute for NIPSCO's local electric sources in reliably meeting electric capacity and service needs. Considering that these distributed generation resources have no guarantee of power dispatch, operate in a "take it as we make it" mode, and can permanently cease operations at any time, results in a lower confidence level regarding the availability of power supply at all times, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all of its service obligations to its customers.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO Distribution Planning continues the expansion of DA. This can be defined as the coordinated automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's DA System enables control and automatic isolation of electric distribution line faults and the restoration of customer services during various system outage conditions. This action is accomplished through independent sectionalizing of specific circuits through the use of automatic line switches and computer-controlled substation breakers. Built-in algorithms are utilized to analyze operating conditions such as line and substation loading, to determine best response to system disturbances. Automatic restoration increases distribution system reliability by reducing the number of customers experiencing a sustained outage. In addition to the quick restoration of electric service, real-time operating data can also be retrieved and stored on the electric management system. DA Systems provide timely and accurate outage-related information to restoration teams, speeding up problem identification. This action supports quicker overall response time to identify system problems and develop repair procedures. These factors result in further improvements in customer service and system reliability. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for operation and maintenance of the electric distribution system.

NIPSCO currently utilizes DA (communications and remote switching) on approximately 25% of its distribution substations and 30% of its distribution circuit population. Approximately two-thirds of all DA associated circuits utilize autonomous contingency switching equipment in their operations. All new and rebuilt distribution substations, and associated circuits, are assessed for need of distribution automation as part of their infrastructure projects. As part of annual system capital investment programs, new and/or rebuilt substation projects are being implemented at an approximate rate of one to two stations per year.

NIPSCO continues to evaluate the benefits of smart grid and DA technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to compliance, stewardship, and continuing to provide energy in an environmentally responsible way. NIPSCO's current electric generation portfolio consists of assets that includes coal and natural gas plants, wind contracts, and hydroelectric power plants. Environmental improvement targets were announced in 2017, and this resource plan contemplates a transition of coal generation assets to renewable energy that would result in enhanced environmental improvements in electric generation by 2028 (from 2005 levels), as follows:

- 90% Reduction in Greenhouse Gas ("GHG") Emissions
- 99% Reduction in Water Withdrawal and Wastewater Discharge
- 99% Reduction in NO_x Emissions
- 99+% Reduction in SO_2 and Mercury Emissions
- 100% Reduction in Coal Ash Generated

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in the NiSource Environmental, Health & Safety and Climate Change Policies and is implemented through a comprehensive environmental management system. Compliance plans are developed, reviewed, and evaluated for implementation to meet new and changing legislative and regulatory developments.

NIPSCO uses a combination of external and internal resources to develop and adapt environmental compliance plans. Consultants and engineering firms are utilized to assist NIPSCO in developing cost estimates and performing modeling. Compliance plans are drafted to address proposed and final EPA and Indiana Department of Environmental Management ("IDEM") rules. As rules change, compliance plans are modified to comply with new requirements.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of Coal Combustion Residuals ("CCR") which became effective on October 19, 2015. The CCR rule regulates CCRs under the Resource, Conservation, and Recovery Act (RCRA) Subtitle D as nonhazardous. The CCR rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and document management.[14] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

To comply with the rule, NIPSCO is required to incur capital expenditures to modify its infrastructure and manage CCRs. Capital compliance costs for Schahfer Units 14 and 15 and Michigan City Unit 12 are expected to total approximately $193 million. Schahfer Units 17 and 18 will not incur any capital costs related to the CCR rule. On December 13, 2017, the IURC approved a set of projects related to CCR compliance in Cause No. 44872. NIPSCO continues to assess and monitor groundwater quality at Bailly, Michigan City, and Schahfer to comply with CCR rule requirements and to determine if historic CCR management and disposal practices will require corrective measures.

7.3.2 Clean Water Act

The CWA establishes water quality standards for surface waters as well as a permit program for regulating discharges into the waters of the United States. Under the CWA, EPA created a program to establish wastewater discharge standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions.

7.3.3 Effluent Limitations Guidelines

EPA first promulgated the Steam Electric Power Generating Effluent Guidelines and Standards ("ELG Rule") in 1974, and has amended the regulation many times, with the latest revision finalized on November 3, 2015, with an effective date of January 4, 2016. The ELG rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. The ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's electric generating facilities to be applied between 2018 and 2023. For example, the Michigan City NPDES permit was renewed in April 2016, and ELG requirements were incorporated effective November 1, 2018. On April 25, 2017, the EPA published notice in the Federal Register stating that the EPA is reconsidering portions of the ELG Rule in response to several petitions for reconsideration. On September 18, 2017, the EPA postponed the earliest compliance dates for FGD wastewater and bottom ash transport water requirements from 2018 to 2020 to potentially consider revisions to technology and numeric limits achievable.

Michigan City Unit 12 is equipped with a dry FGD, which does not require any capital expenditure for ELG rule compliance. The CCR-related infrastructure investment will allow Michigan City to comply with other aspects of the ELG Rule by the November 2018, NPDES permit compliance date. Furthermore, no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18, which, based on this resource plan, NIPSCO anticipates retiring by 2023.

[14] https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

7.3.4 Clean Air Act and Climate Strategy Assessment

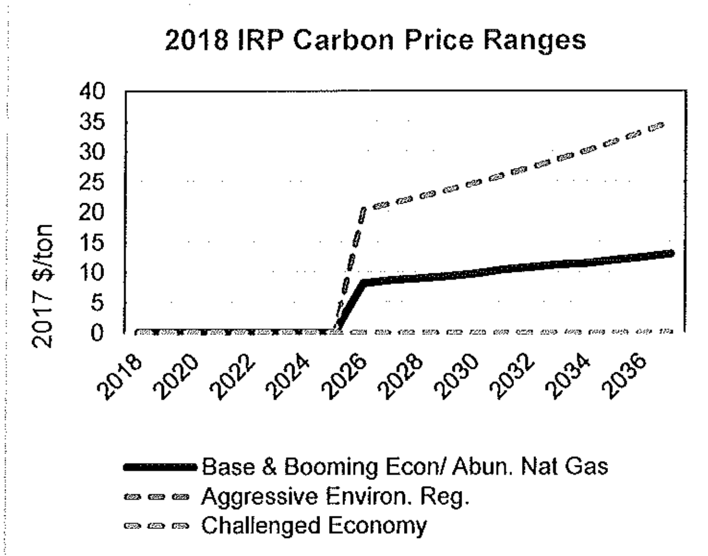
Over the last decade, NIPSCO has invested more than $800 million in new technologies to reduce emissions at its electric generating stations, improve air quality, and comply with CAA requirements. Emissions of NO_x, SO_2, and mercury have been reduced by more than 80% since 2005. All Northern Indiana counties are in attainment of the National Ambient Air Quality Standards with the exception of the ozone standards in Lake and Porter Counties, which are included in Chicago metropolitan area nonattainment.

NIPSCO has reduced GHG emissions by more than 40% since 2005, and emissions reductions are expected to continue with the anticipated retirement of coal generation and transition to renewable energy. Still, climate-related environmental laws and regulations may be developed that could result in significant cost or restrictions on NIPSCO's operations.

On October 23, 2015, the EPA issued a final rule, the CPP, to regulate CO_2 emissions from existing fossil-fuel electric generating units ("EGUs") under authority of the CAA. The CPP establishes national CO_2 emission standards that are applied to each state's mix of affected EGUs to establish either state-specific rate-based or mass-based emission limits. The U.S. Supreme Court has stayed implementation of the CPP until litigation is decided on its merits, and the EPA has proposed to repeal the CPP. On August 31, 2018, the EPA proposed to replace the CPP with the Affordable Clean Energy ("ACE") rule. The timing and cost of compliance with the ACE rule are unknown at this time and are likely dependent on future state rulemaking.

Although the timing and magnitude of required GHG reductions are uncertain, it does not appear likely that a price on carbon emissions will be required by regulation or legislation until the year 2026 or later. In the IRP modeling, NIPSCO assumed three carbon price scenarios as shown in the figure below. The base scenario assumes a new federal rule or legislative action effective by the mid-2020s, the second scenario does not assume any price on carbon, and the Aggressive Environmental Regulation scenario assumes a new stricter federal rule or legislative action effective by the mid-2020s. In the Aggressive Environmental Regulation scenario, price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.

Figure 7-1: 2018 IRP Carbon Price Ranges



This resource plan considered the framework by Ceres and M.J. Bradley & Associates, *Climate Strategy Assessments for the U.S. Electric Power Industry: Assessing Risks and Opportunities Associated with a 2-Degree Transition and the Physical Impacts of Climate Change.* NIPSCO used scenario analysis to assess the potential implications of climate change and inform its strategy. The plan to transition coal generation assets to renewable energy would reduce NIPSCO greenhouse gas emissions by more than 90% by 2028 compared with 2005 levels.

Retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures to reduce NOx emissions in addition to expenditures for CCR, ELG, and GHG compliance. The IRP modeling assumed compliance with updates to the Cross-State Air Pollution Rule ("CSAPR") and ozone regulations that have not yet been proposed. Although both Schahfer Units 17 and 18 are already equipped with low-NO_x burners and OFA systems for NO_x reduction, SCR or selective non-catalytic reduction ("SNCR") could be installed for post-combustion NO_x control. SCR technology allows for greater NO_x reduction rates which leads to better operational flexibility. Therefore, SCR technology was assumed for compliance with the anticipated regulation. Conceptual cost estimates were used in the modeling.

7.4 Emission Allowance Inventory and Procurement

7.4.1 Title IV Acid Rain - SO_2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate SO_2 emissions. Table 7-1 lists the actual number of SO_2 Acid Rain Program emission allowances held in inventory by NIPSCO as of September 2018 for the period 2018 through 2048. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-1: SO_2 Acid Rain Program Emission Allowances

Acid Rain Program SO_2 Allowance Inventory*	
Year	**Allowances**
Bank**	264,764
2018-2048 Annual Allocation	50,706
Total* **	**1,836,650**

* Allowance inventory available in September 2018
** Reflects emission allowances from 2017 and earlier
***To obtain the total, multiply the annual allocation by 31 and add the bank.

7.4.2 CSAPR Emission Allowance Inventory

Under CSAPR, allowances are allocated to NIPSCO and managed separately from the Acid Rain Program. Table 7-2 lists the annual SO_2, annual NO_x, and ozone season NO_x allowance inventory issued to NIPSCO. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the CSAPR rule.

Table 7-2: CSAPR Allowance Inventory

CSAPR Allowance Inventory*			
Year	**Annual SO_2**	**Annual NO_x**	**Ozone Season NO_x**
Bank**	81,347	2,402	444
2018 – 2020 Annual Allocation	23,522	13,178	3,321
Total* **	**151,913**	**41,936**	**10,407**

** Allowance inventory available in September 2018.*

*** Reflects emission allowances from 2017 and earlier.*

****To obtain the total, take the annual allocation and multiply by three and add to the bank.*

Section 8. Managing Risk and Uncertainty

8.1 Introduction & Process Overview

In the 2018 IRP, NIPSCO has deployed an approach that involved the development of a fundamentals-based set of key Base Case market drivers and assumptions and the use of both scenarios and stochastics to assess risk and uncertainty. NIPSCO developed the major inputs and associated uncertainty ranges for the 2018 IRP through the following process:

- Development of the Base Case set of assumptions through fundamental energy sector and commodity price models and NIPSCO's internal load forecasting models.
- Identification of the key drivers of uncertainty and whether they can be evaluated through scenarios or stochastics.
- Development of distinct scenario themes with accompanying model-based forecast assumptions.
- Development of stochastic distributions for relevant variables.

The major market assumptions for the base case and the scenarios were developed using a set of fundamental market models deployed by CRA and discussed in more detail in Section 2.3. These models include the NGF model for natural gas price projections, the NEEM model for electric sector capacity expansion and retirement decisions and coal pricing, and the Aurora model for granular power price projections.

The following sections provide an overview of the fundamental drivers that underpin the NIPSCO Base Case for gas prices, coal prices, carbon prices, and power market prices, while the remainder of the chapter discusses the scenarios and associated assumptions and the stochastic distributions that have been developed.

8.2 Base Case Market Drivers and Assumptions

8.2.1 Natural Gas Prices

NIPSCO's 2018 Base Case natural gas price forecast is driven by a number of key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-1 summarizes the major drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. The remainder of this section provides additional detail related to each driver.

Figure 8-1: Natural Gas Price Drivers – Base Case

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

*IP = Initial Production

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the Potential Gas Committee ("PGC") 2016 "minimum" value as the starting value for recoverable shale reserves, with the resource base growing over time at a steady rate until the PGC "most likely" value is reached in 2050. The assumed values and ranges are shown in Figure 8-2.

PGC evaluates three categories of potential resource:

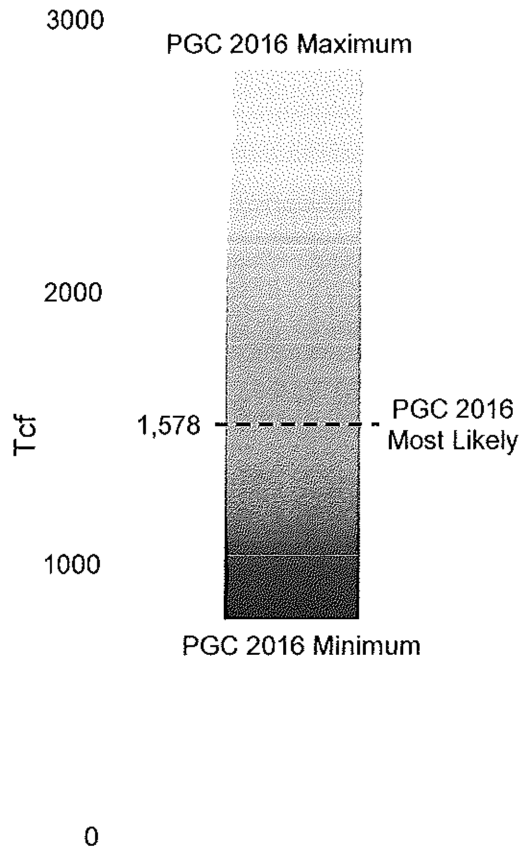
- Probable – gas associated with known fields
- Possible – gas outside of known fields, but within a productive formation in a productive province
- Speculative – gas in formations and provinces not yet proven productive

PGC assigns resource to three probability categories:

- Minimum – 100% probability that resource is recoverable
- Most Likely – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions

- Maximum – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

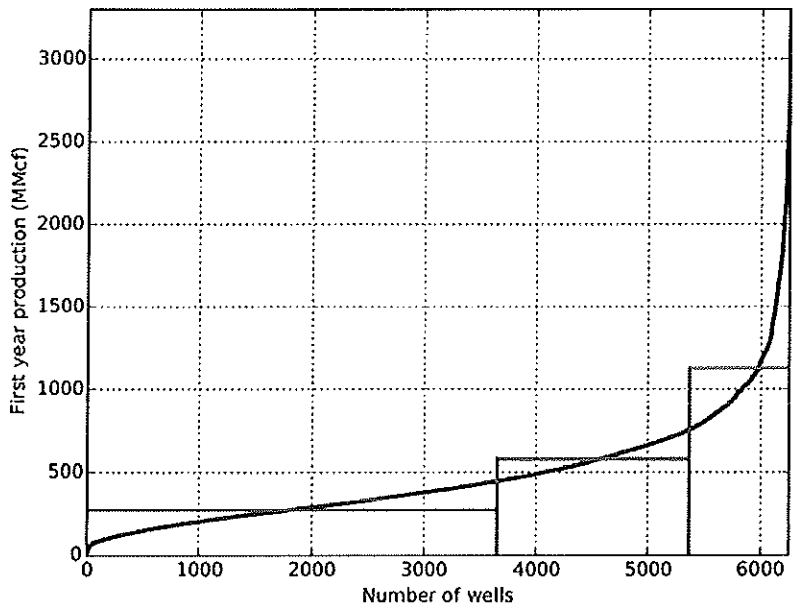
Figure 8-2: Uncertainty Range for Shale Resources in PGC 2016



Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on 2010-2016 drilling data in regions that producers expected to have favorable geology. An example of this distribution is shown in Figure 8-3, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis. In the Base Case, CRA assumed a "Poor Heavy" productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource, as summarized in the graphic.

Figure 8-3: Well Productivity Illustration

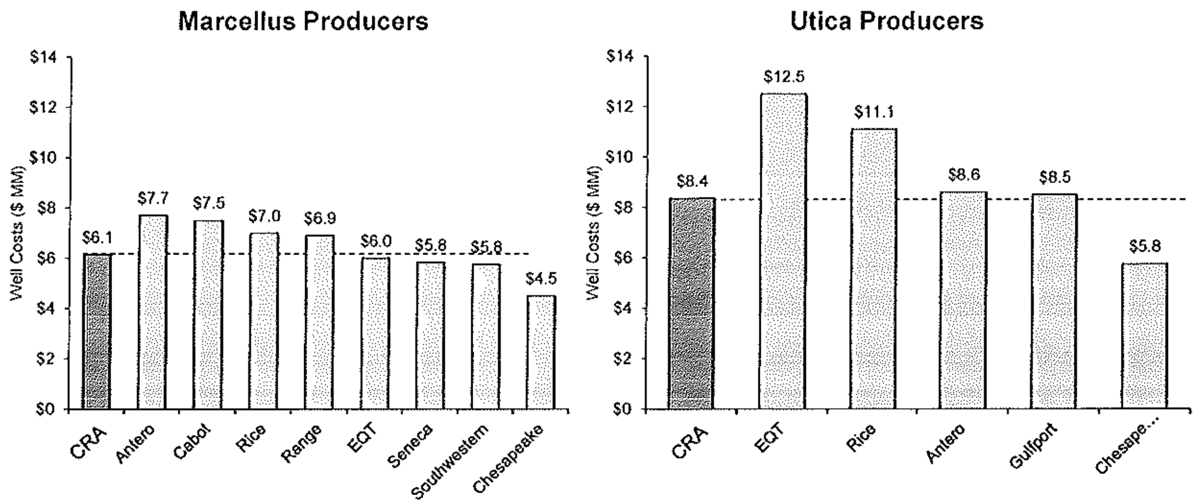


Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Figure 8-4 illustrates 2016-2017 reported costs in the Marcellus and Utica basins across major producers. Producers in these regions have been reporting declining costs over the last several years, with some producers (Antero, Seneca, Chesapeake) reporting cost reductions up to 35-37% since 2014.

For going forward costs, CRA relies on the EIA's Annual Energy Outlook ("AEO") projections for productivity improvements, fixed costs, and operations and maintenance costs. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods.

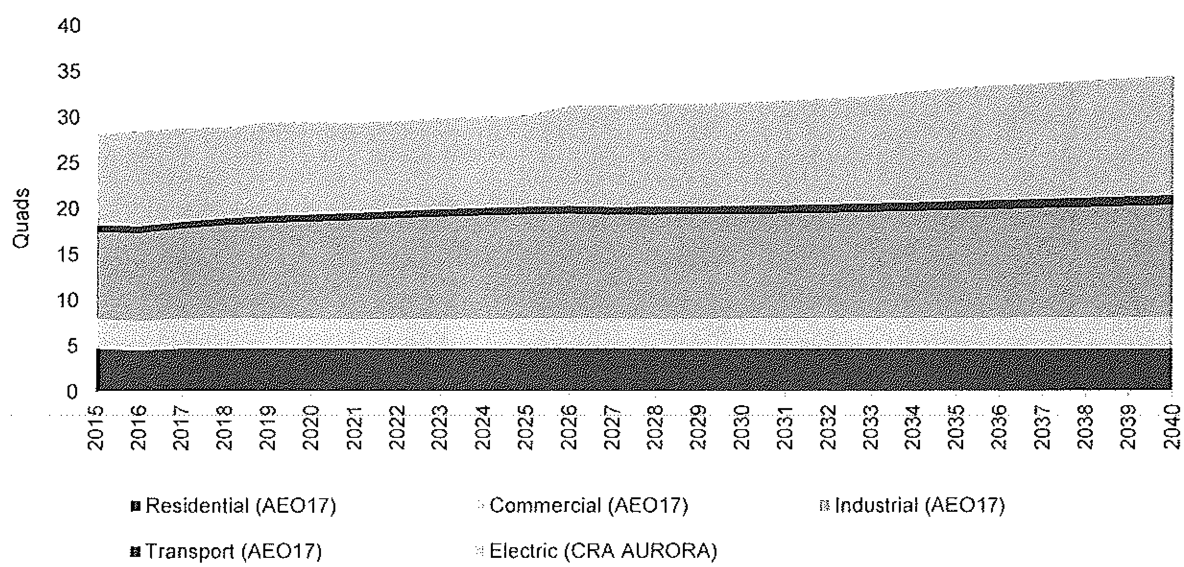
Figure 8-4: Well Costs by Producer with CRA Average



Domestic Demand

In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-5 presents historical and forecast domestic demand assumptions through 2040 from these sources. Electric sector demand is expected to be relatively flat in the near-term, but increase substantially after the potential introduction of a carbon price, such that the demand by 2040 is 30% higher than current levels. The AEO's growth expectations for other sectors are more modest, with some growth expected in the industrial and transportation sectors over time.

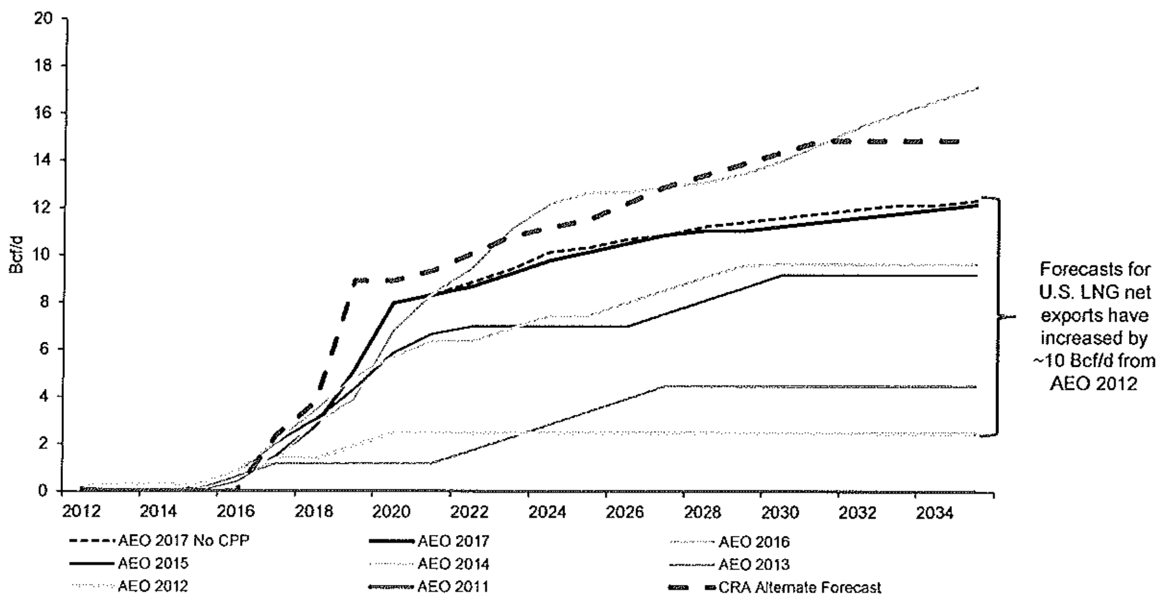
Figure 8-5: Domestic Natural Gas Demand Assumptions



Exports – LNG and to Mexico

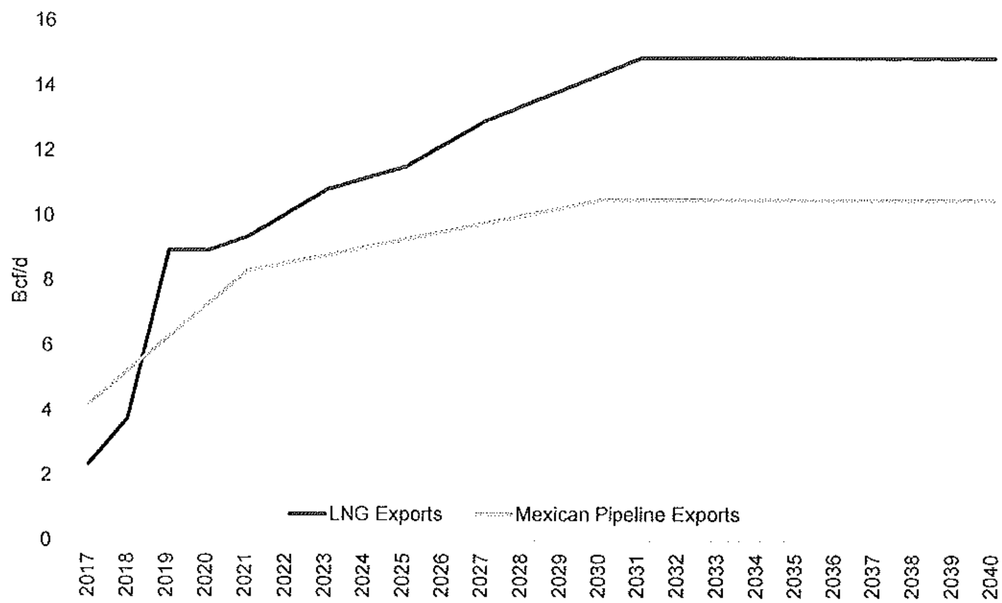
CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and conducting analysis of specific export projects under development. The AEO has generally increased its outlook in recent years, as LNG exports in the AEO 2017 Reference Case are between 25%-35% higher than those in the AEO 2015, although lower than the more bullish long-term outlook produced in AEO 2016. CRA's review of current LNG export projects suggests that export levels will be slightly higher than AEO 2017 projects. The Base Case forecast projects about 9 billion of standard cubic feet ("bcf")/day of LNG exports by 2020, rising to nearly 15 bcf/day by 2030. CRA's Base Case projection is shown with recent AEO projections in Figure 8-6.

Figure 8-6: LNG Export Volume Projections



In addition, CRA expects that exports to Mexico will also increase, as U.S. production grows and as Mexican demand increases, primarily due to additional demand from the power sector. Mexican exports are projected to increase to around 8 bcf/day by 2021 and 10.5 bcf/day by 2030. These Base Case projections are shown along with the LNG export projections in Figure 8-7.

Figure 8-7: LNG and Mexican Pipeline Export Projections



Base Case Price Forecast

CRA's Base Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 8-8. The Base Case projects prices at Henry Hub to increase to around $3.50/ million per British thermal unit ("MMBtu") in real 2017$ by the early 2020s and approach $4/MMBtu by 2030. Recent AEO forecasts are shown with CRA's Base Case for comparison.

8.2.2 Coal Prices

NIPSCO's 2018 Base Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States. The forecast was developed through CRA's NEEM model in an integrated fashion with other Base Case assumptions for natural gas prices (discussed above), carbon prices (discussed below), and the expected evolution of the power sector over time.

Overall, U.S. coal prices are expected to be mostly flat in real terms over the study period. The forward prices as of the time of forecast production were generally either flat or slightly backward-dated, indicating that many market participants expected relatively weak coal demand during 2018-2021, consistent with CRA's expectations. Beyond the near-term, CRA's fundamental analysis expects U.S. steam coal demand to fall significantly (~25%) over the next decade as a result of increased renewable generation and the retirement of about 33 GW of coal-fired capacity over the next five years. Increasing production costs offset the impact of declining demand in the Base Case forecast, resulting in a relatively flat price outlook.

Coal Supply and Demand Trends

Figure 8-9 summarizes historical and projected supply and demand for U.S. coals over the period from 2006 through 2037, which shows that coal demand has generally been in decline over the last ten years. Over the last three years, total coal production declined from 897 million tons to about 728 million tons (or 19%) between 2015 and 2016, but then increased 6.5% (to about 775 million tons) in 2017 as natural gas prices recovered from low levels in 2016. Modest additional declines are expected in the next five years, with more substantial declines expected by 2027 if carbon pricing is implemented, as is projected in the Base Case.

Figure 8-8: Base Case Henry Hub Natural Gas Price Forecast

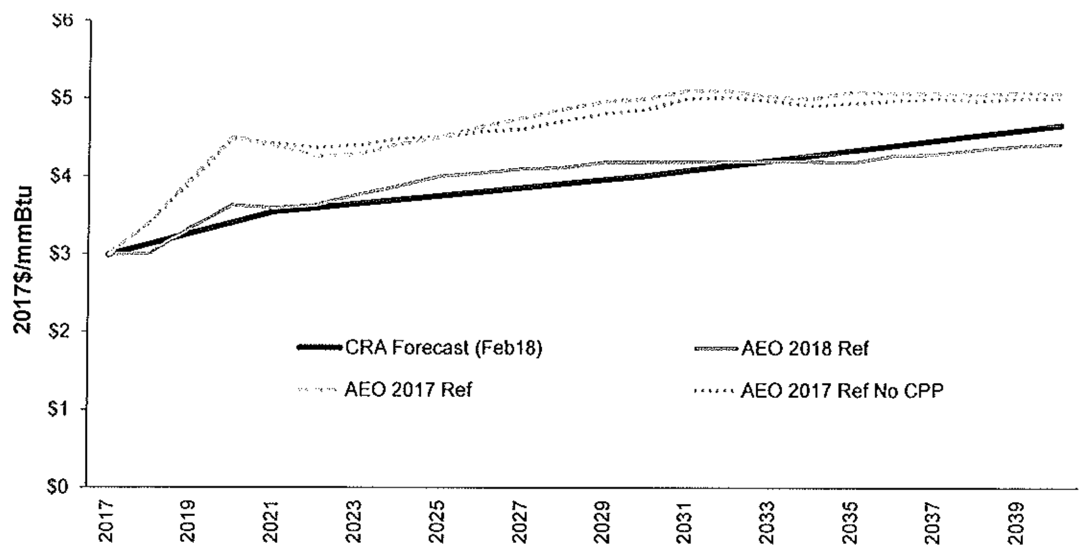
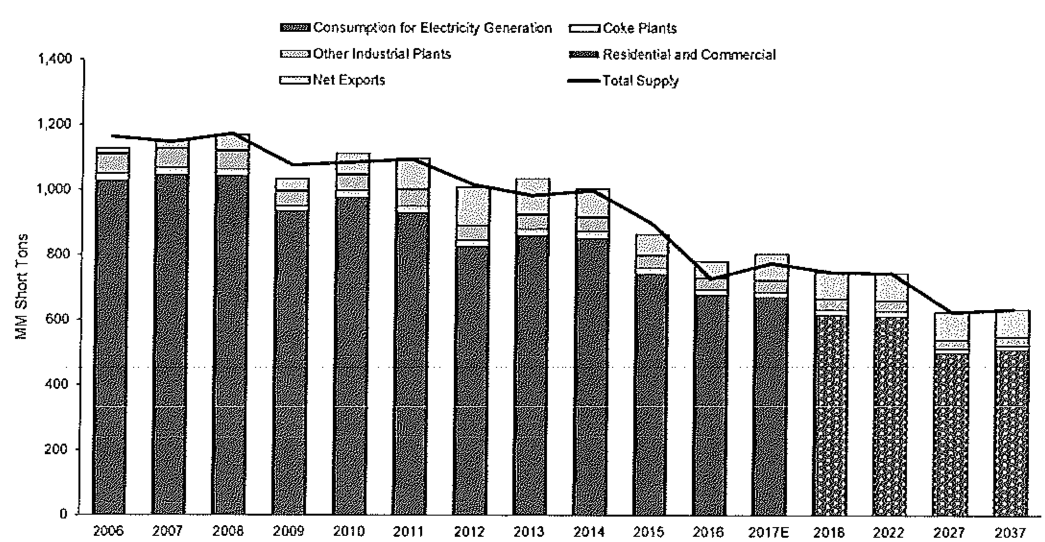


Figure 8-9: Supply-Demand Balance for U.S. Coal – 2006-2037



Regional Coal Production Expectations

While coal demand is broadly expected to decline across the U.S., each of the four major basins faces different dynamics based on regional demand from coal-fired power plants as well as international export demand. Figure 8-10 presents CRA's Base Case production estimates over the next ten years for each of the four major production basins.

Figure 8-10: Ten-Year Coal Production Expectations by Basin

Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

CAPP = Central Appalachian

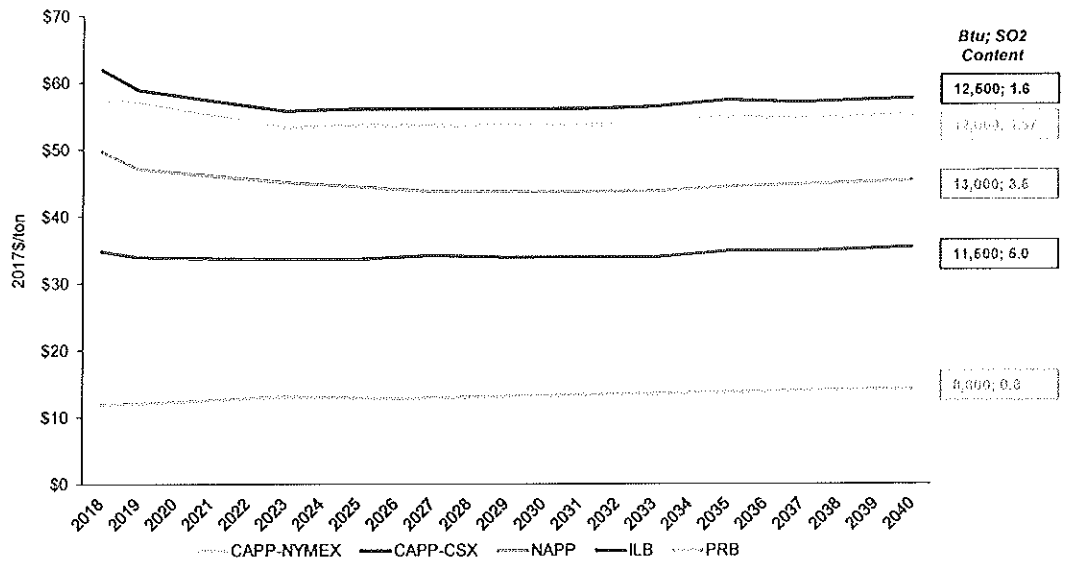
Base Case Price Forecast

CRA's Base Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels, which are represented as coal supply curves within the NEEM model. Figure 8-11 presents the Base Case price outlook by coal supply region, with additional basin-level commentary provided below:

- Central Appalachia ("CAPP"): Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s. Thereafter, reserve depletion is expected to drive modest increase in real coal price for Appalachian coals.
- NAPP: Prices for NAPP coals trend with CAPP, but reflect the lower production costs in Northern Appalachia. NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves.
- ILB: Abundant reserves of ILB coal and low production costs (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth.

PRB: Prices are expected to increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period. This price growth is driven by higher production costs due to downward-sloping coal seams and reserve depletion, even as demand is expected to decline.

Figure 8-11: Base Case Coal Price Forecast

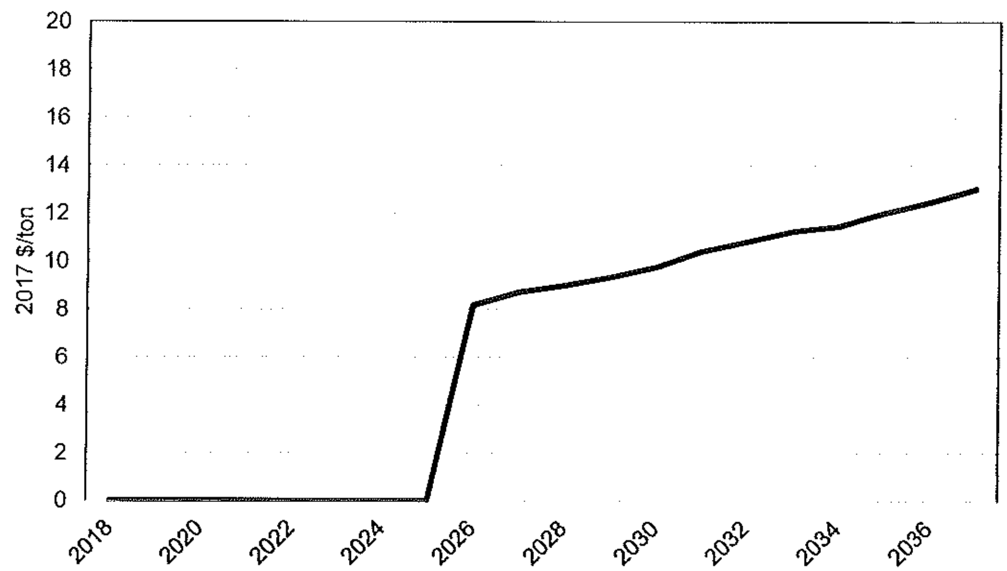


8.2.3 Carbon Policy and Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. While the EPA has been given the authority to regulate carbon emissions, the Obama administration's CPP was held up in the federal courts and eventually withdrawn by the Trump administration. Although regulation that would implement a carbon price does not currently exist, NIPSCO believes that it needs to plan for the potential of such federal regulation to be implemented over the next decade.

As a result, the Base Case forecast includes a price on carbon, premised on a new federal rule or legislative action coming into force by 2026. The Base Case timing implies that a new federal administration after 2020 would need to re-promulgate a rule through the EPA or pursue a legislative solution with a newly constructed Congress. The Base Case expectation is that a new carbon regulation would be in line with the CPP and would aim to achieve 30-40% reductions in emissions from the electric sector versus an historical baseline likely to be set around the time of rule passage. CRA's analysis suggests that pricing between $8-14/ton between 2026 and 2037 would achieve such reductions and result in a 20% reduction in U.S. coal demand. The pricing outlook assumed in the Base Case is shown in Figure 8-12 in real dollars per short ton.

Figure 8-12: Base Case Carbon Price Forecast



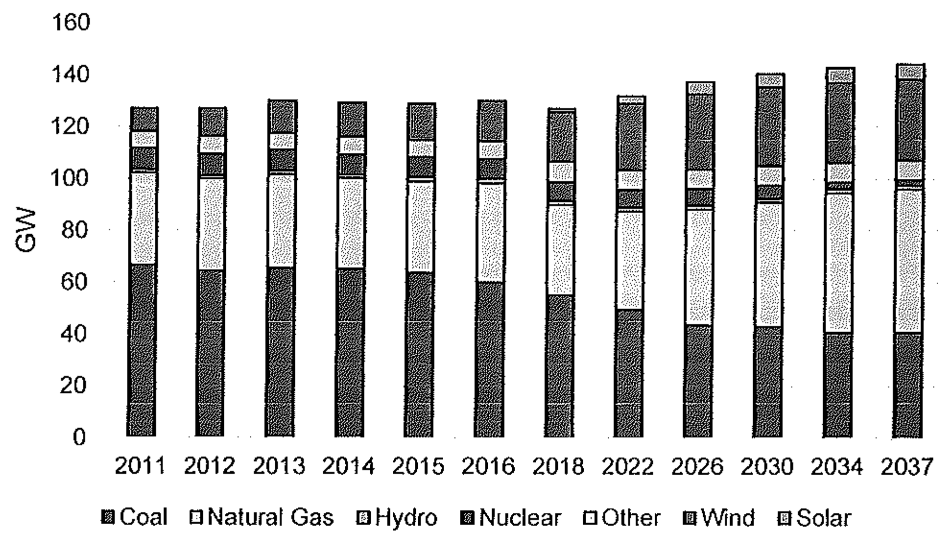
8.2.4 MISO Energy and Capacity Prices

NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana. NIPSCO territory and resources fall within LRZ6, covering Indiana and northern Kentucky. In developing the Base Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly price projections that are internally consistent with the fundamental outlook for natural gas prices, carbon prices, and the future capacity mix in the region.

MISO Capacity Mix

Based on the market inputs from fuel and carbon prices, the Base Case analysis expects a continued shift from coal capacity to natural gas-fired capacity and renewables throughout MISO. Between 2011 and 2016, 7.5 GW of coal capacity retired in the MISO North region, with a net decline of 6.3 GW, due to some additions that came online prior to 2013. The Base Case forecast expects that an additional 10.5 GW of MISO North coal capacity will retire by 2023. Over half of the coal fleet is at least sixty years old, and pressure from potential carbon prices and competition from natural gas-fired and renewable resources, which are realizing lower costs, is likely to result in further retirements over time. CRA's projection of the evolution of the MISO North capacity mix is presented in Figure 8-13.

Figure 8-13: MISO North Net Winter Capacity by Fuel Type – History and Forecast



MISO Electricity Demand Growth

Electricity demand growth in MISO has been relatively modest in recent years, with total net energy for load growing at a compound annual growth rate of 0.4% between 2010 and 2016. While energy demand within the Indiana zone has grown at a rate of around 1% per year since 2010, peak load has been quite flat over the same time period. Going forward, CRA's Base Case expects MISO peak loads to grow at a 0.24% compound annual growth rate over the next ten years. This outlook is based on MISO Module E filings rather than the Independent Load Forecast, which historically has projected higher growth rates.

Base Case Energy Price Forecast

CRA's Base Case MISO market analysis uses the load growth projections, expectations for supply mix changes, and fuel and emission price forecasts to develop forecasts for power prices on an hourly basis. Overall, power prices are projected to be relatively flat in real dollars in the near-term, due to flat gas and coal prices and relatively modest load growth. Some upward pressure is expected into the 2020s as a result of higher natural gas price projections, although growing renewable quantities are likely to lower the market heat rate over time. The expectation for a national carbon price, starting in 2026, drives a noticeable price increase in that year. On a seasonal basis, market prices are expected to be highest in the summer months when load is highest, but also to display increases during the winter months when load is elevated and when gas prices are likely to be high as a result of winter heating demand. Figure 8-14 presents the annual Base Case power price projections for the Indiana region, which is LRZ6, while Figure 8-15 presents the same projections on a monthly basis.

Figure 8-14: LRZ6 (Indiana) Base Case Annual Price Projections

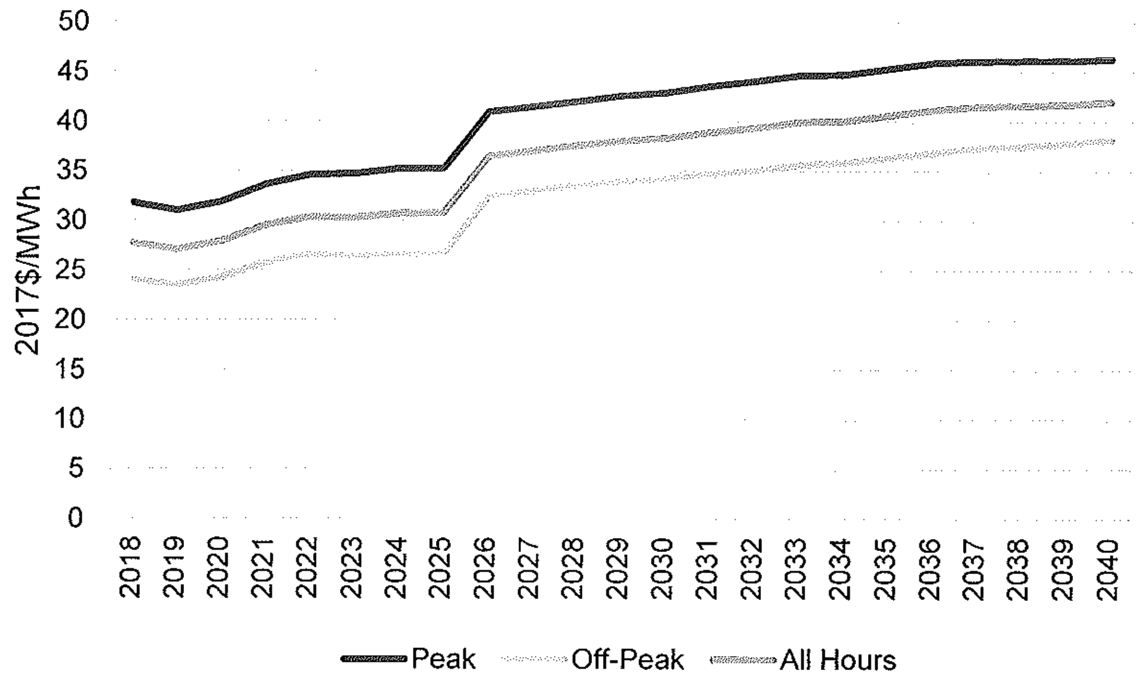
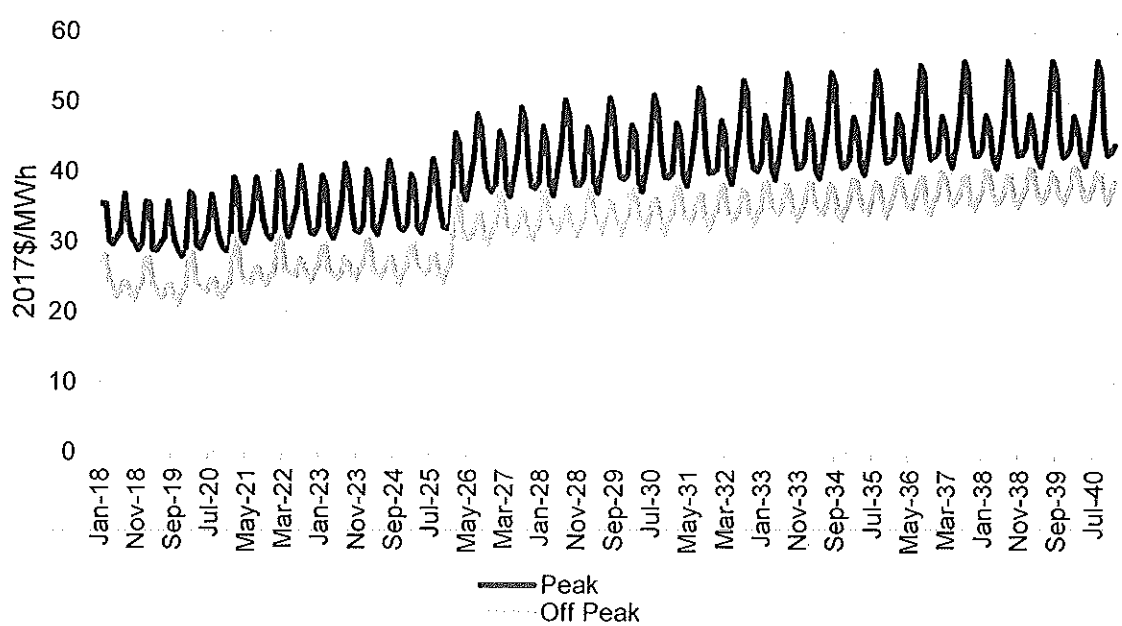


Figure 8-15: LRZ6 (Indiana) Base Case Monthly Price Projections

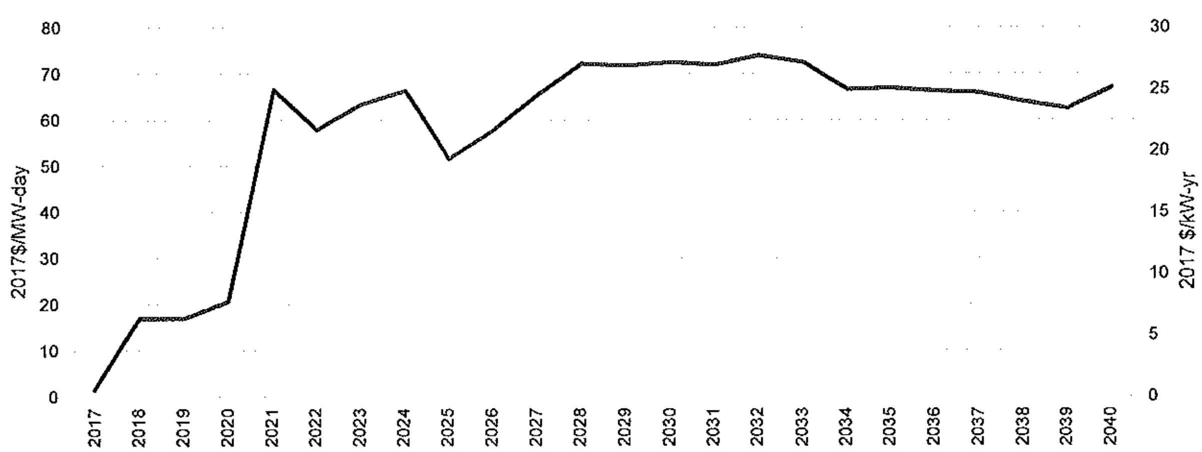


Base Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in an annual auction. The capacity market is based on an administratively-set demand requirement and supply offers from market participants that are willing to sell capacity. Recent market prices have been relatively low even as coal capacity retires as a result of flat load, increases in renewable capacity, and increases in behind-the-meter, demand response, and energy efficiency supply. Furthermore, recent tariff revisions have impacted reduced supply offer thresholds, resulting in clearing prices around or below $10/MW-day in recent auctions.

CRA's capacity price forecast includes a fundamental evaluation of supply and demand in the market, as well as the expected offer prices for generators throughout the market. CRA expects low market prices to persist through 2021, when coal and nuclear retirements may drive prices up towards the going-forward costs of existing units. The Base Case does not expect increases in price towards MISO's cost of new entry (CONE) benchmark even as new capacity is needed, since it is likely that electric utility builds, under cost-of-service ratemaking, will enter the market and keep reserve margins in the 17-19% range. Figure 8-16 presents the Base Case capacity price projections over time.

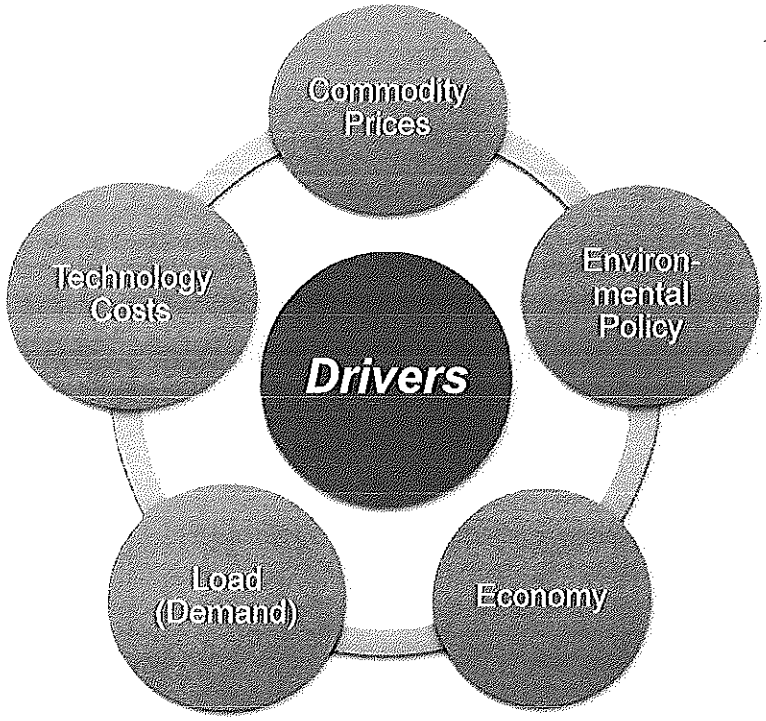
Figure 8-16: MISO Capacity Price Projections



8.2.5 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

After defining the Base Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact its business environment and future portfolio performance over the long-term. Drawing on its work from the 2016 IRP, NIPSCO identified five major drivers of uncertainty, as shown in Figure 8-17. These include commodity prices, especially for natural gas, power, and coal; environmental policy, particularly with regard to carbon pricing; economic growth, including its impact on electric sector load growth and commodity prices; NIPSCO load growth, and technology costs for new resources.

Figure 8-17: Major Drivers of Uncertainty



After identifying the major drivers of uncertainty, NIPSCO then assessed whether they should be addressed through scenario or stochastic analysis. In the 2018 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across both scenarios and stochastics since the two approaches answer different questions and quantify risk in different fashions. Scenarios can be structured to assess major changes to specific market driver assumptions, along with related feedbacks, while stochastics can evaluate volatility and tail risk, based on observed historical data, particularly in the commodity price markets. Figure 8-18 provides a summary of the primary purposes and benefits of using deploying each approach. Based on NIPSCO's review of the different uncertainty approaches, it was determined that stochastic distributions would be developed for natural gas and power commodity prices and evaluated in concert with the ranges established through a fundamental scenario development process.

Figure 8-18: Scenario and Stochastic Uncertainty Approaches

Scenarios
Integrated Set of Assumptions

- Can be used to answer "What if..."
- Major events can change fundamental outlook for key drivers, altering portfolio performance
  - New policy or regulation (carbon regulation)
  - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
  - Loss of a major load
- Can tie portfolio performance directly to a "storyline"
  - Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- Can evaluate volatility and "tail risk"
  - Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness
  - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed three scenarios to supplement the Base Case, relying on the foundation that was built in the 2016 IRP process, but incorporating recent trends and specific risks related to the 2018 IRP Base Case assumptions. A summary of the scenario themes is shown in Figure 8-19.

Figure 8-19: Scenario Theme Overview

Theme	Drivers			
	Technology	Policy	Load	Economy
Base Case	Expected continued declines in solar/storage costs; base case nat. gas production costs	National carbon price expected in 2026 with new federal policy; current regulations on CCR/ELG	Base load forecast	Long-term growth trends in line with historical averages
Aggressive Environmental Regulation	**Renewable (wind and solar) and storage costs decline significantly, supported by policy push**	**Policy forces drive stricter carbon controls and stronger renewable targets**	Base load forecast	Reference case macroeconomic factors persist
Challenged Economy	Base technology assumptions	**No national carbon policy**	**Loss of industrial load; remaining customer load growth stagnates**	**Economic downturn with growth stalling**
Booming Economy & Abundant Natural Gas	**Continued efficiency gains in NG extraction drive lower operations costs and focus on most productive plays**	Base environmental policy; strong support for gas extraction	**Greater load growth, maintenance of industrial customers**	**Low-cost energy paradigm prevails and economic growth greater than expected**

NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of load, carbon price, natural gas price, coal price, and power price based on additional rounds of modeling with CRA's fundamental market tools. Given that NIPSCO's All-Source RFP resulted in a range of resource technology costs to use in the IRP analysis, this variable was not specifically evaluated in the scenario development phase. Figure 8-20 summarizes the directional movement of the key input assumptions relative to the Base Case, while the subsequent section of this chapter outlines the detailed inputs that were developed as part of the scenario analysis process.

Figure 8-20: Summary of Four Major Scenarios

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	High	High (CO_2)	Low (CO_2)	High (CO_2)
Challenged Economy	Low	Low	Low (No CO_2)	High (No CO_2)	Low (No CO_2)
Booming Economy & Abundant Natural Gas	High	Base	Low	Low (Low Gas)	Low (Low Gas)

8.3 IRP Scenarios

8.3.1 Aggressive Environmental Regulation Scenario

Description

The Aggressive Environmental Regulation Scenario represents a future in which environmental regulations will be more stringent than currently anticipated for power sector emissions, particularly related to carbon dioxide. As a result, carbon environmental compliance costs will be greater for NIPSCO than in the Base Scenario, starting at about $20/ton in real dollars in 2026, escalating to about $35/ton (real dollars) by 2037. Natural gas prices will be greater as a result of greater demand from gas in the power sector as coal generation declines. In the scenario, natural gas prices are projected to trend towards $5.50/MMBtu in real dollars over time. Coal prices are expected to be lower due to reduced coal demand. Power prices will be greater as a result of both higher carbon prices and higher natural gas prices, even though there is a faster shift in the MISO supply mix from coal to natural gas and renewables. The key directional assumptions changes are summarized in Figure 8-21.

Figure 8-21: Summary of Aggressive Environmental Regulation Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**

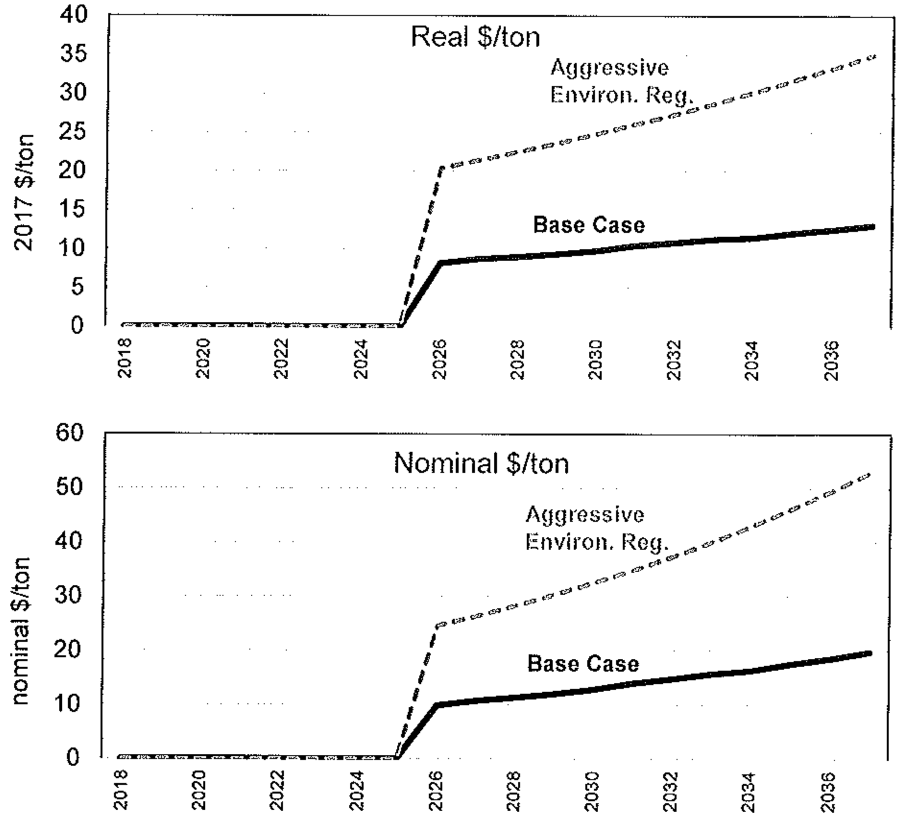
Risks Addressed

The Aggressive Environmental Regulation Scenario addresses the risk that carbon environmental regulations will be more stringent than expected in the Base Scenario. This scenario addresses the risk of higher carbon prices after 2026, which will tend to favor renewable generation and, to a lesser extent, natural gas-fired generation over coal capacity. The scenario also addresses the risk of higher prices for natural gas and power, which are correlated. Assumptions regarding load growth remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

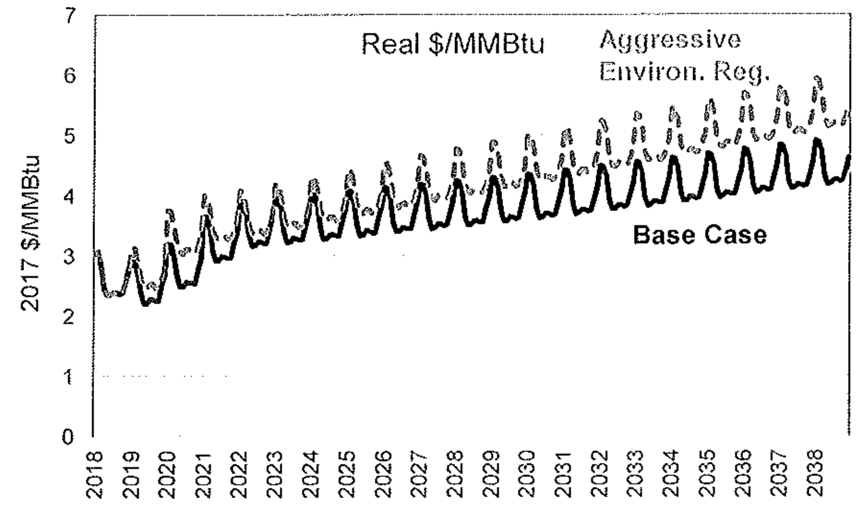
The Aggressive Environmental Regulation Scenario assumes a stricter new federal rule or legislative action on carbon dioxide emissions coming into force by the mid-2020s. Based on CRA's analysis, price levels are generally consistent with a 50-60% reduction in electric sector carbon emissions relative to 2005 by the 2030s. The scenario's timing is the same as the Base Case's, based on the fact that program implementation prior to 2026 is unlikely, given the required changes in executive administration or Congressional control, as well as the potential for legal challenges. This type of policy, however, would represent an initial pathway towards aggressive carbon reduction goals. The carbon prices over time are shown in both real and nominal dollars per ton in Figure 8-22.

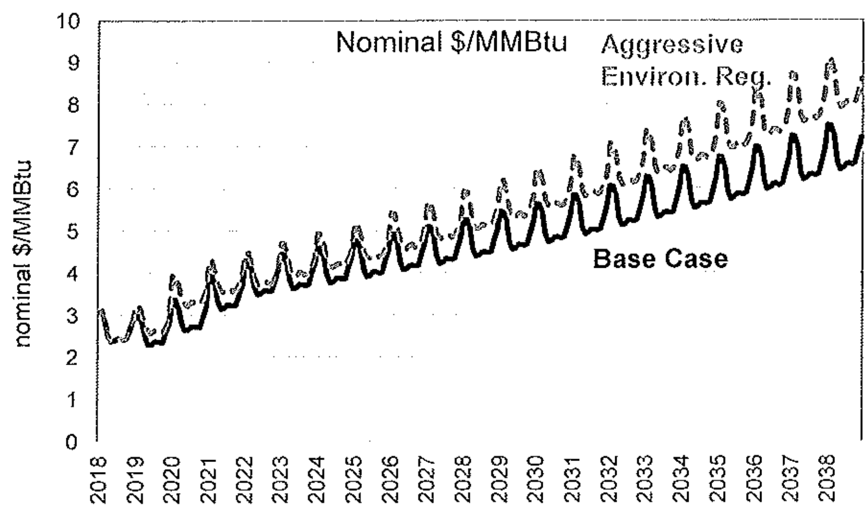
Figure 8-22: Carbon Prices in Aggressive Environmental Regulation Scenario



Such high carbon prices are likely to result in additional coal retirements and less coal generation in the electric power sector. Over the long-term, this is projected to result in higher demand for natural gas, even as renewable generation also expands significantly. The long-term increase in natural gas demand in the power sector is projected to be around 15%. CRA's NGF modeling projects that such an increase in gas demand will result in upward pressure on long-term gas prices on the order of about $1/MMBtu (real). The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-23.

Figure 8-23: Natural Gas Prices in Aggressive Environmental Regulation Scenario

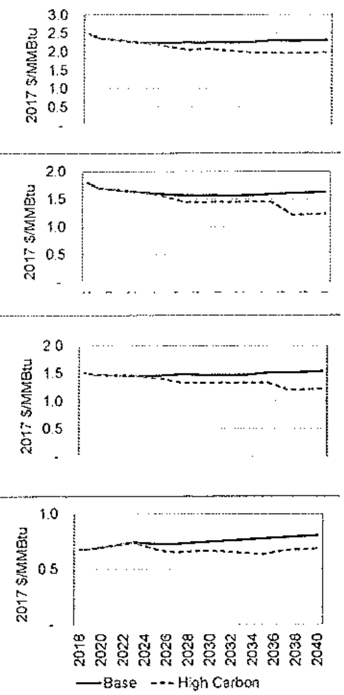




While demand for natural gas is projected to increase, demand for coal is likely to decline in the Aggressive Environmental Regulation Scenario due to reduced coal plant dispatch and additional coal retirements. In this scenario, coal demand is broadly expected to be around 10-20% lower than the Base Case in 2026 (the first year of the carbon price) and 30-50% lower over the long-term. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.10-$0.40/MMBtu lower than those in the Base Case. Figure 8-24 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Aggressive Environmental Regulation Scenario in real 2017 dollars.

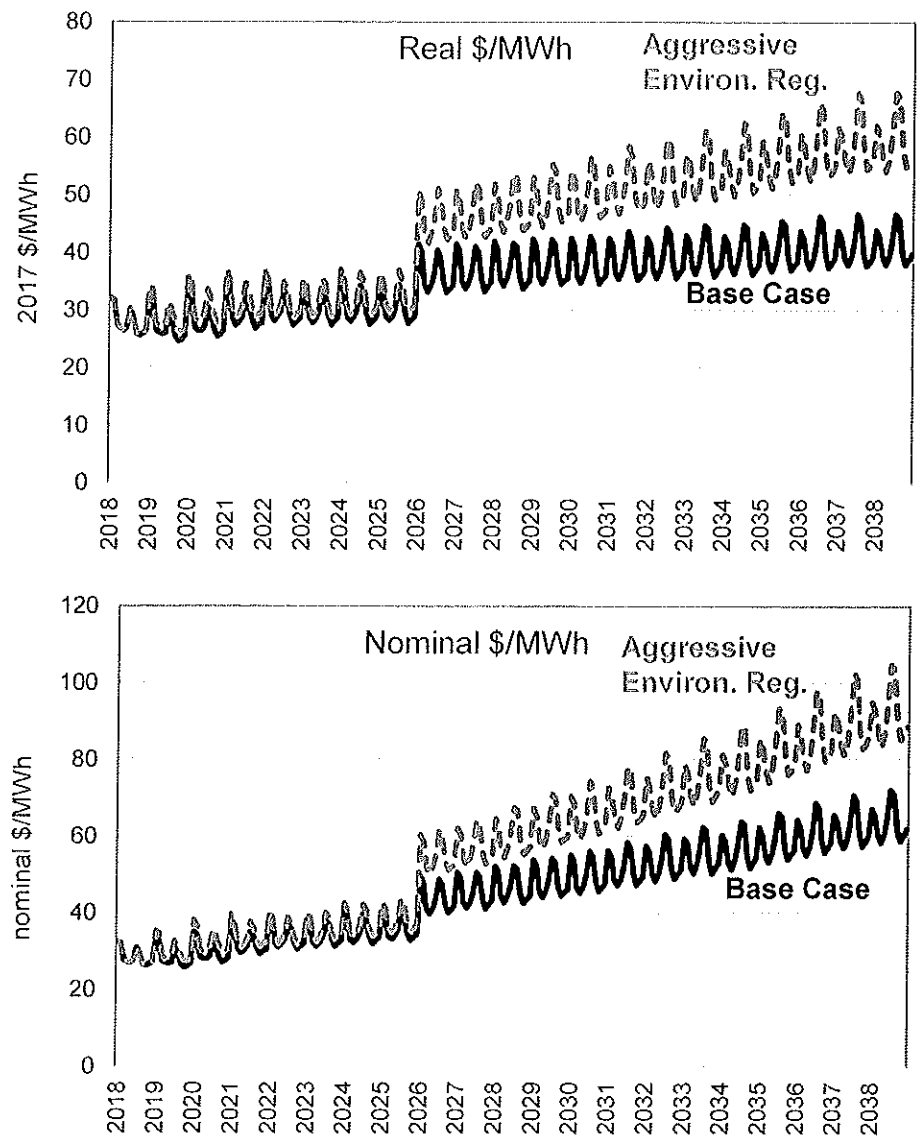
Figure 8-24: Coal Demand and Prices in Aggressive Environmental Regulation Scenario

Coal	Base Case	High Carbon Case
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 keeps long-term prices declining, down $8-10/ton ($0.30/MMBtu) vs. base
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in 2026 and **-30 -35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**-20%** in demand in 2026 and **50%+** decreases thereafter drives prices down $2/ton (~$0.10/MMBtu)



The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Aggressive Environmental Regulation Scenario. Over a twenty-year period, coal generation in MISO is expected to decline by nearly 70% in this scenario, while natural gas and renewable generation are expected to make up the difference. Although renewable generation is significantly higher than in the base case, higher gas and carbon prices result in higher variable costs for the type of plant most often setting the market price in MISO. Over time, this drives average, around-the-clock ("ATC") LRZ6 power prices up by about $20/MWh (in real dollars) by the late 2030s. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-25.

Figure 8-25: LRZ6 Power Prices in Aggressive Environmental Regulation Scenario



8.3.2 Challenged Economy Scenario

Description

The Challenged Economy Scenario represents a future where economic growth is stagnant and environmental policy is focused on maintaining low energy prices through limited federal regulation of carbon emissions from the power sector. The scenario is premised on the assumption that federal regulation that would result in increased energy costs would be unlikely if economic growth is low. Thus, this scenario has no price on carbon and assumes that any future emission regulation is based on plant-specific efficiency measures or other rules without a specific cap or tax on emissions. As a result of weaker economic growth and no price on carbon, demand for natural gas is expected to fall over time, keeping natural gas prices stable at around \$3.50/MMBtu (real dollars) over time. Stronger coal demand is expected to result in modestly increasing coal prices versus the Base Case. Under these scenario assumptions, fewer coal retirements and fewer renewable additions are expected when compared to the Base Case. Natural gas resources are expected to remain marginal during most hours, and lower gas prices and no carbon price result in a relatively flat power price forecast in real terms over time. Finally, under the assumption that economic growth impacts demand for electricity, including industrial demand, the Challenged Economy Scenario includes a lower load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-26.

Figure 8-26: Summary of Challenged Economy Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Challenged Economy	Low	Low	Low (No CO_2)	High (No CO_2)	Low (No CO_2)

Risks Addressed

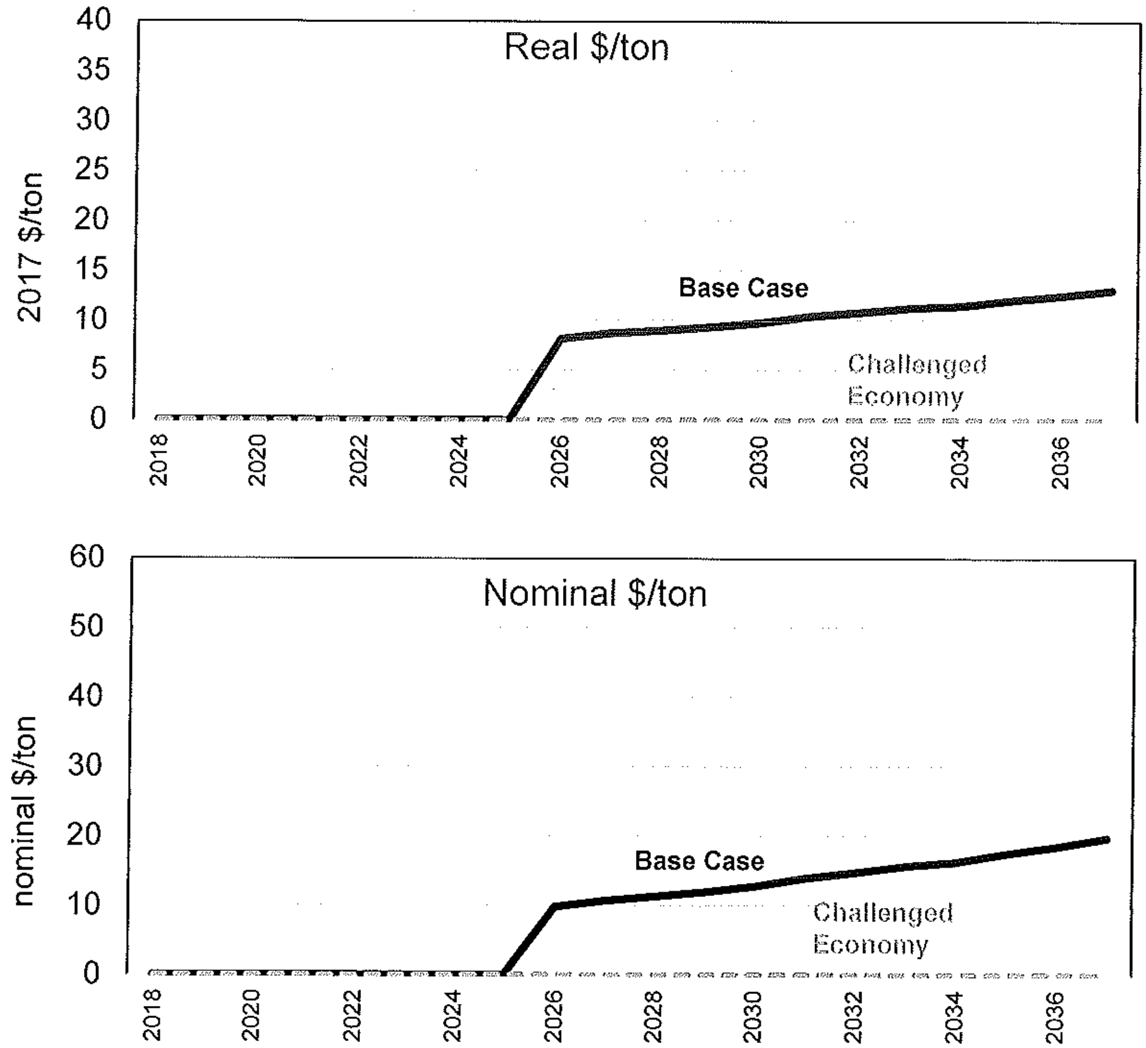
The Challenged Economy Scenario addresses the risk of an economic downturn as well as the risk of no carbon price coming into effect over the study horizon. The scenario addresses the combined risks of very low load growth, no carbon price, and low commodity prices for gas and power. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are never priced, testing the robustness of portfolios against this important risk.

Detailed Scenario Assumptions

The Challenged Economy Scenario assumes no federal price on carbon, as shown in

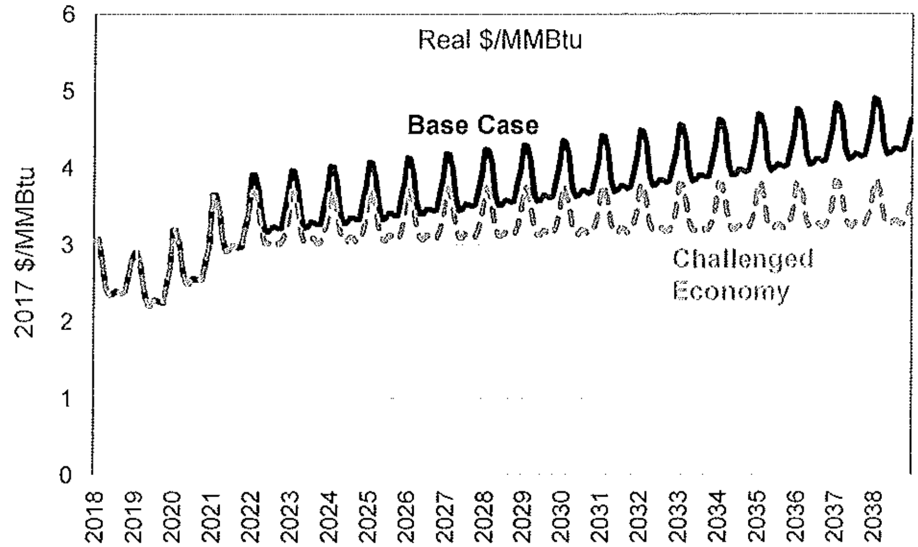
Figure **8-27** versus the Base Case. This scenario assumes that EPA regulation is broadly consistent with the recently proposed ACE rule, which focuses on heat rate efficiency improvements for existing coal plants. This proposed rule and other future regulations under this scenario would avoid specific tax-based costs or an emission cap requirement.

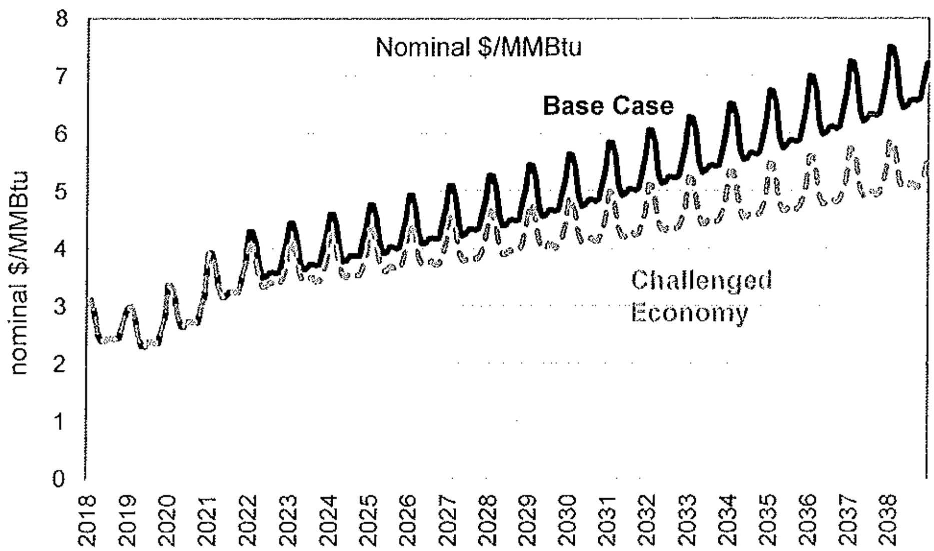
Figure 8-27: Carbon Prices in Challenged Economy Scenario



Lower carbon prices and lower overall electric demand growth are expected to reduce natural gas demand over time. CRA's modeling has found that, rather than increasing like in the Base Case, power sector natural gas demand is projected to be relatively flat over the next twenty years in the Challenged Economy Scenario. This is due to higher levels of coal generation, as well as continued renewable additions, driven by state-level policy. These expected power sector dynamics result in 15-20% lower natural gas demand than in the Base Case, flattening the natural gas price outlook at around $3.50/MMBtu (real dollars). This results in long-term prices that are about $0.90/MMBtu (real dollars) lower than those in the Base Case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-28.

Figure 8-28: Natural Gas Prices in Challenged Economy Scenario

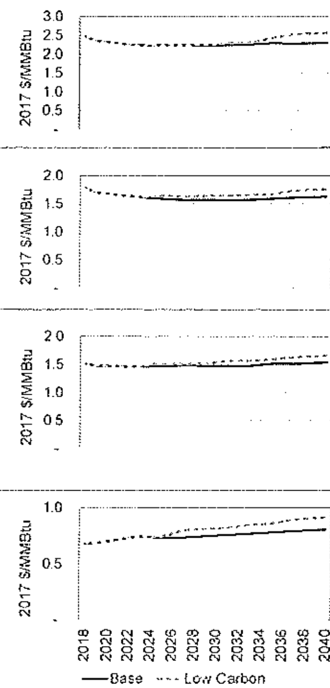




While demand for natural gas is projected to decrease, demand for coal is likely to increase in the Challenged Economy Scenario due to increased coal plant dispatch and fewer coal retirements without the influence of a carbon price. In this scenario, coal demand is broadly expected to be around 10% higher than the Base Case in 2026 (the first year of the carbon price in the Base Case) and 0%-30% higher over the long-term. The impacts vary based on coal production basin, but such demand increases are projected to result in price that are $0.10-$0.25/MMBtu higher than those in the Base Case. Figure 8-29 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Challenged Economy Scenario in real 2017 dollars.

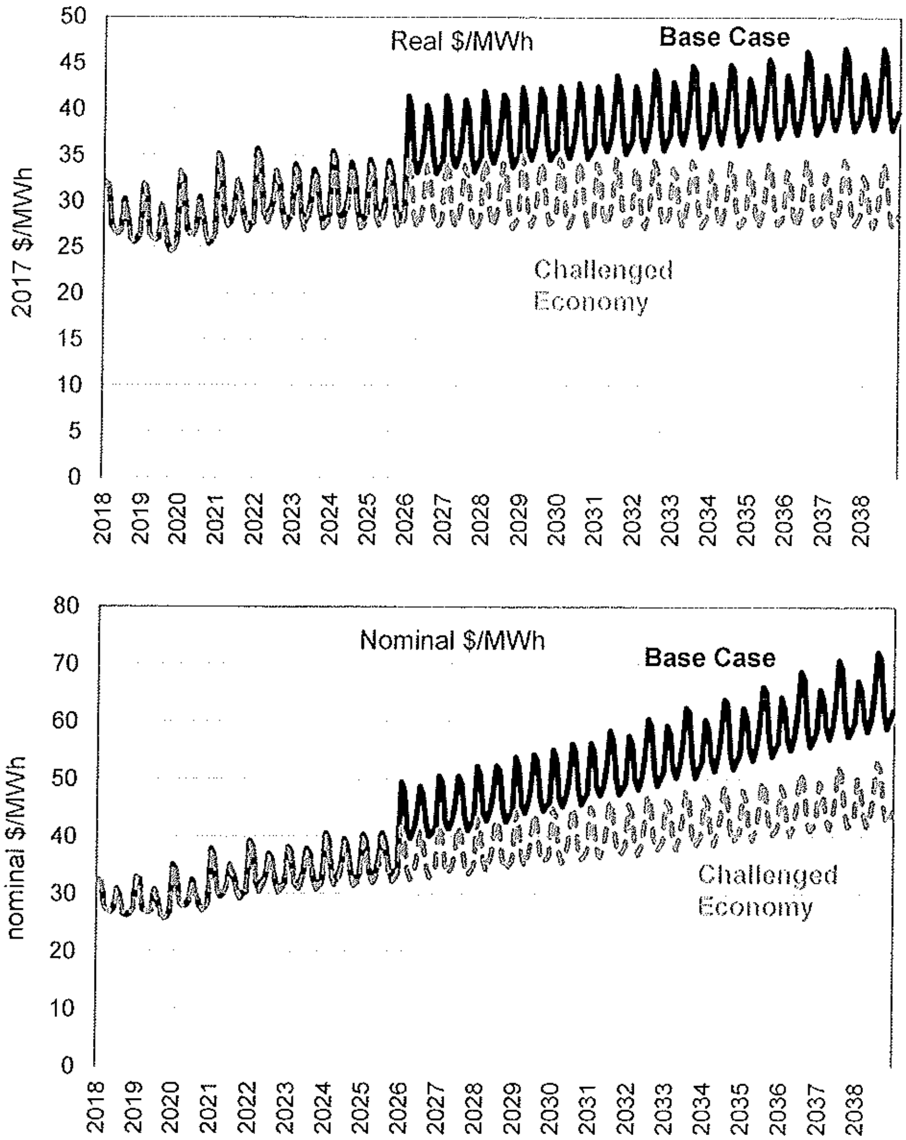
Figure 8-29: Coal Demand and Prices in Challenged Economy Scenario

Coal	Base Case	Low Carbon Case
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	Initial **+10-20%** impact in demand, but long-term demand similar to base case; prices initially stable, but increase ~$5/ton ($0.25/MMBtu) due to reserve depletion
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**+10%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton (~$0.10/MMBtu)
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**+6%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton(~$0.10/MMBtu)
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**+13%** in demand in 2026 and **+33%** by 2037 drives prices up $2/ton (~$0.10/MMBtu)



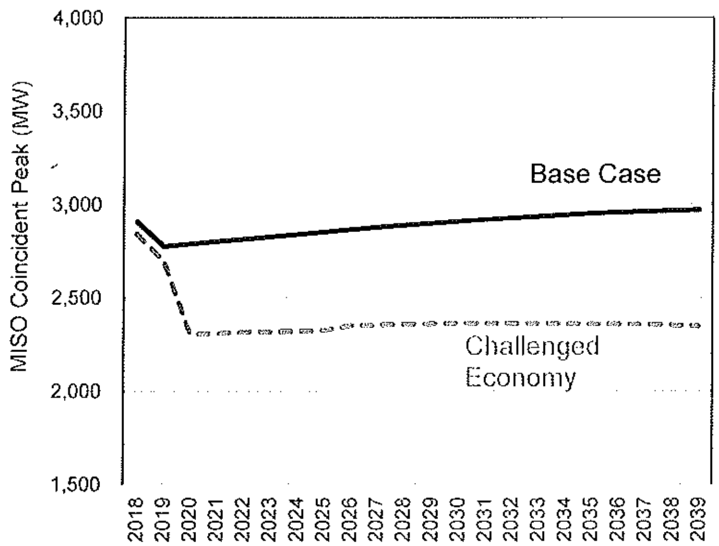
The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Challenged Economy Scenario. In this scenario, coal generation is expected to stabilize after 2026, especially as coal retirements are reduced and as variable costs of operation for coal-fired plants are lower without the presence of a carbon price. The lack of a carbon price and the flatter natural gas price forecast drive power prices down, such that average, ATC prices remain around $30/MWh (in real dollars) over the long-term. This is represents a decrease of about $10-15/MWh (real dollars) versus the Base Case. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-30.

Figure 8-30: LRZ6 Power Prices in Challenged Economy Scenario



As part of the Challenged Economy Scenario, NIPSCO developed a lower load forecast that included the loss of significant industrial demand and lower load growth that is associated with lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-31 summarizes the peak load forecasts for the Base Case and the Challenged Economy Scenario. The compound annual growth rate for the high load trajectory is -0.9% versus 0.10% in the Base Case, primarily due to the significant loss of load assumed by 2020. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-31: NIPSCO Peak Load Growth Forecast in Challenged Economy Scenario



8.3.3 Booming Economy/ Abundant Natural Gas Scenario

Description

The Booming Economy & Abundant Natural Gas Scenario represents a future where natural gas production costs remain low and the resource base remains highly productive, keeping natural gas prices low and flat in real terms over the next decade. Low natural gas costs are a contributing factor to higher economic growth, as low energy prices contribute to higher levels of industrial and commercial economic activity. As a result of the flat forecast for natural gas prices, coal demand is projected to erode, which leads to lower coal prices over time. Power prices remain correlated to natural gas and carbon prices and remain relatively flatter for longer in real terms in this scenario when compared to the Base Case. A spike in power prices is still projected to occur in 2026 with the introduction of a carbon price, which is the same as in the Base Case. Fewer renewables and significantly more coal retirements are projected in the MISO supply mix as a result of very cheap gas over the next ten years. Finally, under the assumption that economic growth remains robust, the Booming Economy/ Abundant Natural Gas Scenario includes a higher load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-32.

Figure 8-32: Summary of Booming Economy/ Abundant Nat. Gas Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Booming Economy & Abundant Natural Gas	High	Base	Low	Low (Low Gas)	Low (Low Gas)

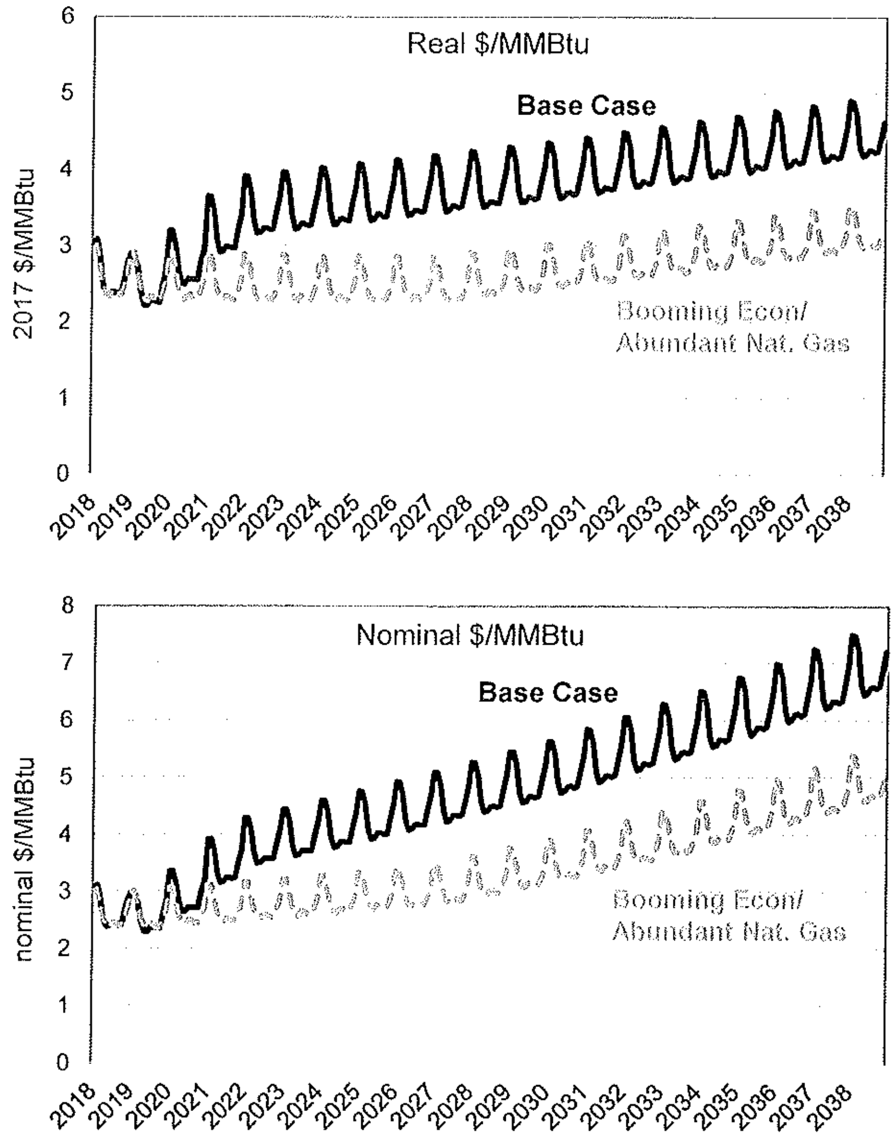
Risks Addressed

The Booming Economy/ Abundant Natural Gas Scenario addresses the risk of higher load growth for NIPSCO versus the Base Case. Higher load growth could result in higher exposure to the MISO market for NIPSCO depending on its portfolio selection. In addition, this scenario addresses the risk of persistently low natural gas prices, which would generally have the impact of favoring the economics of natural gas capacity and harming the economics of coal-fired and renewable generation. Assumptions regarding carbon prices remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

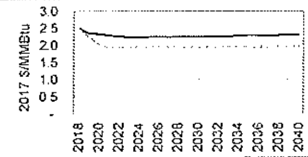
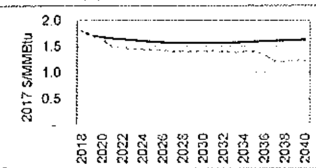
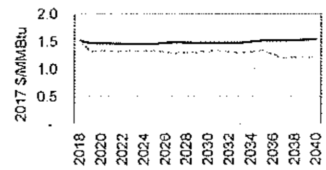
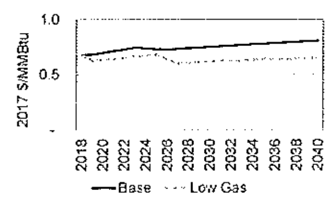
The Booming Economy/ Abundant Natural Gas Scenario assumes that natural gas prices stay relatively low for a longer period of time, primarily as a result of lower production costs. This could be the result of continued expansion of the resource base, producers continuing to effectively hold operations costs down, and producers focusing on the most productive plays for a longer period of time. In order to develop natural gas price projections for this scenario, CRA adopted the long-term forward strip for natural gas for a ten-year period. As of the time of the development of the 2018 IRP assumptions, natural gas forwards at Henry Hub were relatively flat in real dollars at around $2.60/MMBtu for the next ten years. In 2028 and beyond, CRA's fundamental modeling suggested that modest increases in real prices to above $3/MMBtu by the late 2030s were likely in this case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-32.

Figure 8-33: Natural Gas Prices in Booming Economy/ Abundant Nat. Gas Scenario



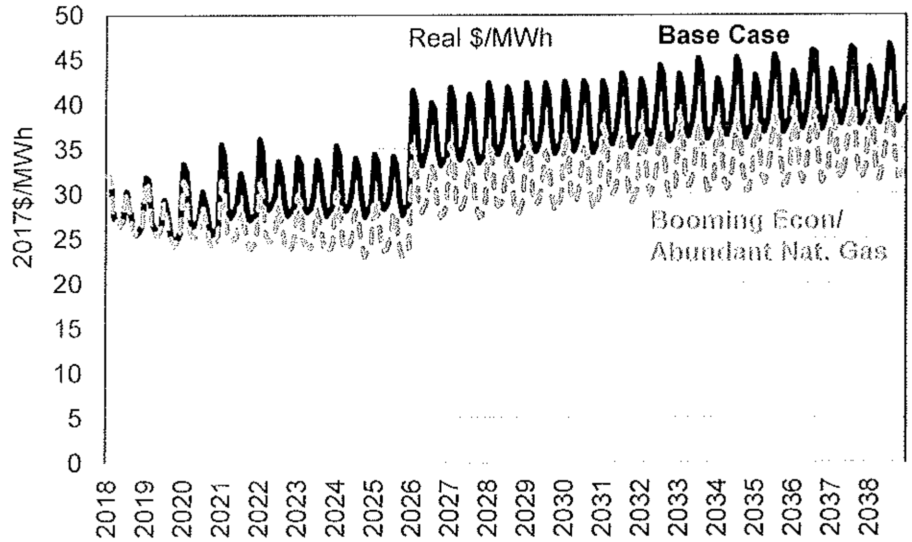
With significantly lower natural gas prices in the Booming Economy/ Abundant Natural Gas Scenario, coal demand is expected to decrease significantly as the variable costs of coal generators remain higher than those of gas plants. In this scenario, coal demand is expected to be significantly lower than the Base Case, with 30-50% lower coal demand expected across most basins, especially with the implementation of a carbon price in 2026. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.15-$0.40/MMBtu lower than those in the Base Case. All coal price forecasts in this scenario are flat or declining in real dollars versus currently market prices. Figure 8-34 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Booming Economy/ Abundant Natural Gas Scenario in real 2017 dollars.

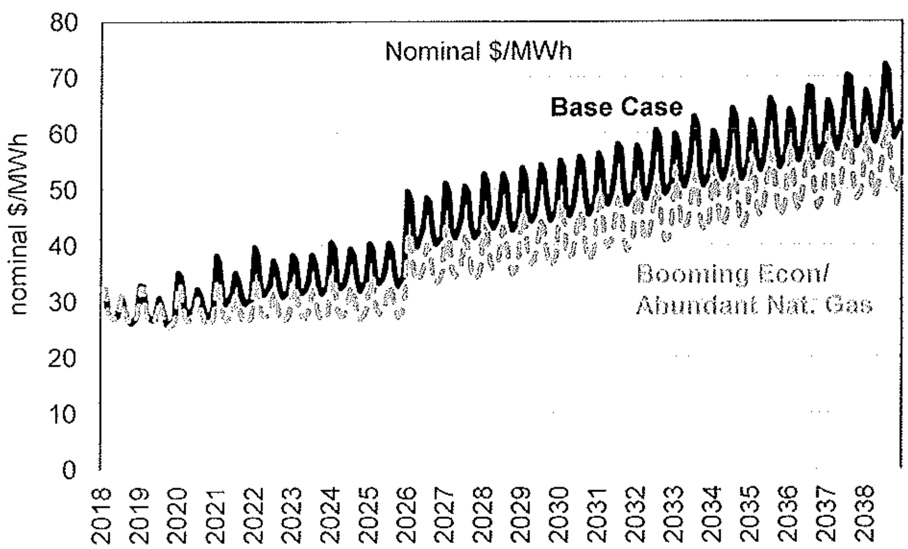
Figure 8-34: Coal Demand and Prices in Booming Economy/ Abundant Nat. Gas Scenario

Coal	Base Case	Low Gas Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-30%** in demand by early to mid-2030s, with flat demand thereafter; long-term prices down $8-10/ton ($0.30/MMBtu) vs. base	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-30%** in demand by mid-2020s, with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in early 2020s and **-30-35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	Immediate demand erosion, growing to **50% decline** in demand in 2026 and more thereafter; drives prices down $3/ton (~$0.15/MMBtu)	

The projected changes in fuel prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Booming Economy/ Abundant Natural Gas Scenario. Similar to the Aggressive Environmental Regulation Scenario, coal generation in MISO is expected to decline by nearly 70% in this scenario over a twenty-year period. The decline in coal generation, however, is more significant in the early years in the Booming Economy/ Abundant Natural Gas Scenario. With gas generation being marginal during more hours with lower gas prices and more coal retirements, the low gas price projections result in power prices remaining very flat in real dollars and below $30/MWh on average through 2025. Although a carbon price is still incorporated in 2026, lower gas prices drive MISO power prices about $5-6/MWh lower than prices in the Base Case after 2030. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-35.

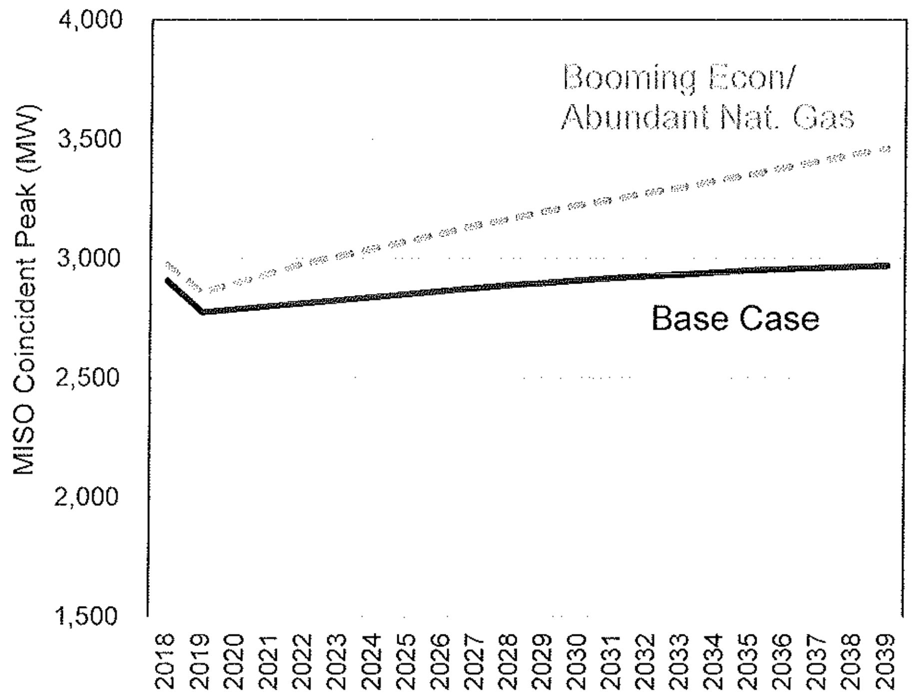
Figure 8-35: LRZ6 Power Prices in Booming Econ/ Abundant Nat. Gas Scenario





As part of the Booming Economy/ Abundant Natural Gas Scenario, NIPSCO developed a higher load forecast that is associated higher lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-36 summarizes the peak load forecasts for the Base Case and the Booming Economy/ Abundant Nat. Gas Scenario. The compound annual growth rate for the high load trajectory is 0.73% versus 0.10% in the Base Case. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-36: NIPSCO Peak Load Growth Forecast in Booming Economy/ Abundant Nat. Gas Scenario



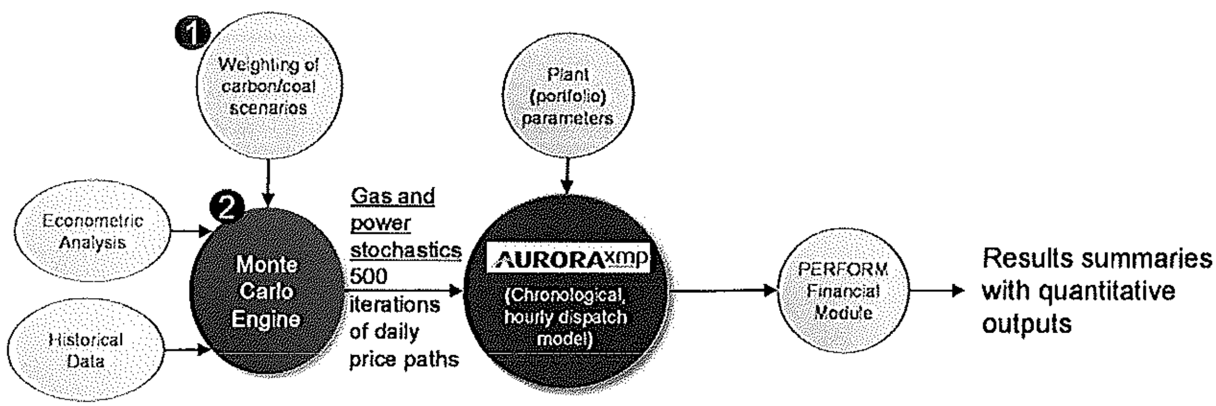
8.4 IRP Stochastics Development

The development of stochastic inputs was a separate, but complementary part of NIPSCO's assessment of risk and uncertainty. As discussed above, NIPSCO determined that stochastic analyses would be performed for key commodity prices with sufficient price history, with the full stochastic distribution of outcomes also including probability weightings for other relevant drivers like carbon prices. Overall, scenario development supported the stochastic parameter definition, with granular distributions of major commodity price inputs developed with CRA's Monte Carlo engine. The major elements of the stochastic input distribution development process included:

1. Establishment of probability weightings for major discrete variables like carbon prices and coal prices, based on the scenario assumptions.
2. Deployment of CRA's Monte Carlo engine to produce daily and hourly price paths for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporated:
   - Daily price spikes for gas; and
   - Power price volatility on a daily and hourly level, implicitly based on historical data observations that include market load shocks, fuel price changes, and plant outages.

Figure 8-37 summarizes the stochastic input development process and how the stochastic inputs were deployed in the IRP models to assess risk and uncertainty for potential portfolio options. As is shown, CRA's Monte Carlo engine relies on econometric analysis of historical price data, as well as weightings for major discrete variables based on the scenario development process. The Monte Carlo engine itself develops 500 iterations of daily and hourly price paths for gas and power prices which are fed into the Aurora model. The Aurora model is then run 500 times, incorporating each set of price paths, along with other market assumptions and portfolio parameters for NIPSCO. The 500 runs are then each analyzed within CRA's PERFORM financial model to estimate revenue requirements and total portfolio costs.

Figure 8-37: Overview of Stochastic Input Development Process



Stochastic Input Development Methodology

The development of stochastic inputs within the Monte Carlo engine incorporated several steps, which are described in more detail below:

- Step 1: Historical Data Analysis – CRA first analyzed historical commodity prices at the liquid commodity price points most relevant to NIPSCO, which included Chicago Citygate for natural gas prices and the Indiana Hub, representative of LRZ6, for power prices. The historical data analysis was performed to find a stochastic (or econometric) model that best captured the observed behavior of prices in the modeled regions. Key statistical parameters were developed from the data analysis in order to define the stochastic price processes. These included:
  - volatility levels (a measure of the price randomness);
  - mean-reversion rate (a measure of the convergence to long-term price trends and forecasts); and
  - the correlation between power and natural gas prices in the regions.
- Step 2: Parameter Estimation – Based on this analysis, CRA then fit the historical data to an econometric model by running regressions and estimating stochastic process parameters.
- Step 3: Monte Carlo Simulations – Based on the parameter estimation, CRA then deployed its Monte Carlo engine to simulate future spot prices for both natural gas and

power. The simulation included the development of 10,000 price paths for each commodity, using antithetic draw techniques to ensure fast convergence and a balanced and risk-adjusted coverage of the full spectra of positive and negative price jumps in the simulated price time series.

- Step 4: Final Probability Distributions for Each Scenario – Given the range of scenario-based inputs for key discrete variables (such as carbon prices), CRA performed the Monte Carlo simulations across multiple fundamental market scenarios and probability-weighted them to develop the full set of stochastics that preserve internal consistency with the fundamentals-based carbon and coal price inputs. In order to develop a set of inputs that could feasibly be run through the Aurora and PERFORM IRP models, 500 draws were sampled for the full portfolio dispatch analysis.

Stochastic Input Distributions

The stochastic input development process results in 500 daily or hourly price paths for the major commodities, which can be summarized with distribution plots showing monthly confidence intervals over time. Probability distribution plots for the twenty-year forecast period for natural gas prices, including historical price data, and power prices are shown in Figure 8-38 and Figure 8-39, respectively. These graphics show, on a monthly level, the broad range of the individual price paths (in gray) along with representations of the monthly confidence intervals at the 5th, 25th, 50th, 75th, and 95th percentiles.

The confidence intervals do not represent specific price trajectories, but instead indicate the probability of the price being at or below the specified level at any given point in time. For example, the top orange line in Figure 8-38 represents the monthly 95th percentile for natural gas prices, which means that 95 percent of the data set is below this price at any given point in time. In other words, five percent of the price observations in any given month across the full distribution would be expected to be above this value. These observations can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. In fact, it is highly unlikely that a single path would be at the 95th percentile for a sustained period of time. Overall, the stochastic inputs allow for evaluation of portfolio performance against extreme price outcomes on the high side and on the downside, including at the daily and hourly price levels, which are not shown in these graphics.

Figure 8-38: Stochastic Distribution for Natural Gas Prices

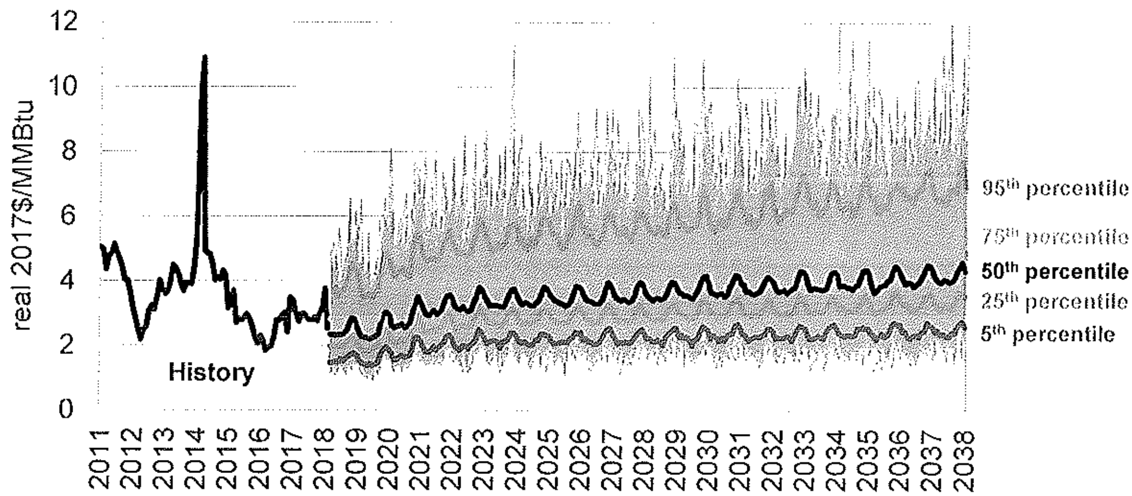
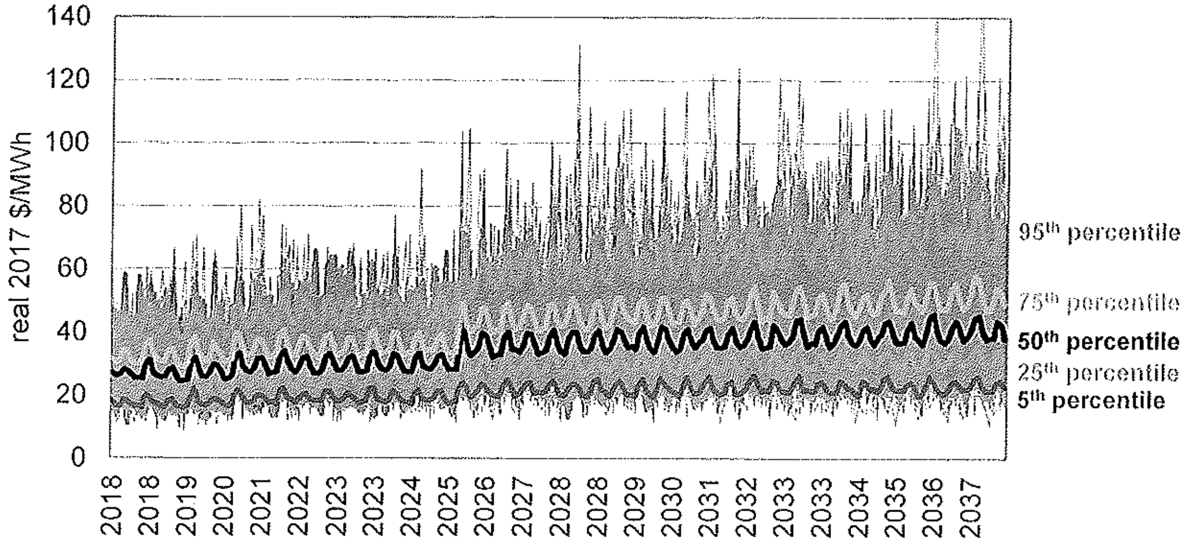


Figure 8-39: Stochastic Distribution for Power Prices



Section 9. Portfolio Analysis

9.1 Retirement Analysis

9.1.1 Process Overview

As in the 2016 IRP, NIPSCO performed a retirement analysis in its 2018 IRP to evaluate the preferred coal retirement strategy over time. Given the number of permutations around the magnitude and timing of potential retirements, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions on a stand-alone basis, while performing an additional replacement analysis to assess a number of replacement resource strategies. Although performed in two steps, the retirement and replacement analyses are both based on the same major inputs and assumptions, which are described in earlier parts of Section 8 and below.

NIPSCO believes that performing a retirement analysis requires careful planning and consideration of several factors in addition to the cost of generation. To that end, NIPSCO has used an integrated scorecard methodology to evaluate retirement portfolios. In addition to the net present value of revenue requirements in the Base Case, NIPSCO has also considered cost certainty and cost risk metrics based on a full stochastic analysis, the ability to confidently transition resources and maintain system and customer reliability, and the effect of unit retirements on NIPSCO's employees, the local economies of the communities it serves, and the environment.

9.1.2 Retirement Analysis Methodology and Results

The retirement analysis has been conducted according to the following steps:

- Identify plausible retirement plans and specify individual retirement combinations or "portfolios"
- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the All-Source RFP conducted by NIPSCO (*See* Section 4.9.2 for additional information on the details of the All-Source RFP.).
- Evaluate each retirement portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this section). The evaluation includes a full accounting of the ongoing operations of each existing plant (including any additional environmental compliance requirements) and the costs of alternatives.
- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred retirement portfolio.

9.1.3 Identification of Retirement Portfolios

All five of NIPSCO's coal-fired units were evaluated for retirement. This includes Michigan City Unit 12 and Schahfer Units 14, 15, 17 and 18. The operational dependency as well as technology and vintage similarity of the Units at Schahfer would make Unit-level retirement impractical. As a result, the analysis created Unit pairs (14&15, and 17&18) that would be jointly considered for retention or retirement. NIPSCO identified eight retirement portfolios for analysis based on different combinations of unit retirements at different points in time. The plans range from one that keeps all existing coal units in service through end-of-life to one that retires all coal in 2023. In between, the portfolios evaluate different levels of retirement at different dates over time. Figure 9-1 provides a summary of the eight portfolios, including the timing of the various retirement permutations and the assumed environmental compliance investments.

Figure 9-1: Overview of Retirement Combination Portfolios

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City in 2035)	**15% Coal in 2023** (Mich. City in 2028)	**15% Coal by 2023** (Schfr. 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr.17,18 (2023)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich.City:12 (2028) Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich.City:12 (2028) Schfr.17,18 (2021) Schfr.14,15 (2023)	Mich.City:12 (2023) Schfr.17,18 (2023) Schfr.14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr.14,15,17,18	Mich. City: 12 Schfr.14,15	Mich. City: 12 Schfr.14,15	Mich. City: 12 (2035) Schfr.14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR* ELG**: non-ZLD***	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes..

*CCR: Coal Combustion Residuals
**ELG: Effluent Limitation Guidelines
***ZLD: Zero-Liquid discharge

9.1.4 Identification of Least-Cost Replacement Capacity

While NIPSCO's 2016 IRP relied on market price benchmarks for replacement capacity and energy, the All-Source RFP conducted in 2018 provided insight into the supply and pricing of alternatives available to NIPSCO. Thus, for the 2018 IRP, data from this process was used to develop detailed cost and operational estimates for the least-cost replacement capacity that was available for each of the eight retirement portfolios.

As discussed further in Section 4, representative replacement resource tranches were constructed from the All-Source RFP results based on technology, ownership structure, cost, and other operational characteristics. Then, all of the resource tranches, along with the bundles developed in the DSM assessment (*See* Section 5.), were available to the portfolio optimization model in Aurora. A portfolio optimization was then performed under each of the eight retirement portfolios to identify a least-cost set of replacement resources for each. The portfolio optimization modeling was performed to minimize the net present value of revenue requirements, with certain constraints for minimum and maximum reserve margins and maximum off-system energy sales.

Overall, the economic optimization model selected a combination of DSM and renewable resources across all retirement portfolios. Along with a small amount of flexible MISO capacity market purchases, the optimization model selected 125 MW of total DSM by 2023, approximately 150 MW of wind (UCAP), and a combination of solar and solar plus storage resources, depending on the capacity gap that was required to be filled. Figure 9-2 provides a summary of the type of capacity that was selected under the various retirement portfolios. Note that this does not represent NIPSCO's preferred replacement strategy, but only a least-cost optimization that is used to evaluate retirement implications.

Figure 9-2: Summary of Least-Cost Replacement Capacity by Retirement Portfolio

COST-EFFECTIVENESS	2 3 4 Schahfer 17/18 Retirement ~600MW UCAP need		5 6 7 Schahfer 14/15/17/18 Retirement ~1,350MW UCAP need		8 All Coal Retirement ~1,750MW UCAP Need	
Higher	TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
	MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
	DSM	125	DSM	125	DSM	125
	Wind	150	Wind	150	Wind	150
	Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
Lower		**715**		**1,395**		**1,825**

9.1.5 Evaluation of Each Retirement Portfolio - Assumptions

Analyses were performed for each of NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. NIPSCO used a number of factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk and impacts to NIPSCO's employees, and the local economy. The evaluation of each retirement portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM. Market assumptions were consistent with those outlined earlier in Section 8 for the Base Case, the three deterministic scenarios, and the full range of stochastic inputs. In addition to the major market inputs and the costs of replacement resources from the All-Source RFP results, several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, maintenance capital, costs associated with future environmental controls, as well as the recovery of remaining book value associated with each plant as of December, 2017. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations.
For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D. As coal units' projected retirement dates move up, the relative capital spend decreases during the years leading up to retirement. This is different than expected fixed O&M costs leading up to a retirement, which stay relatively constant over time, regardless of retirement expectation.

Capital for environmental controls and the associated O&M expenditures that are projected to be required for future environmental compliance are additive to the ongoing capital and O&M expenditures. These incremental capital estimates were provided by NIPSCO's Major Projects department based on outside engineering studies. The most recently available capital estimates, escalated by 2% for inflation, were used in the analyses as specified in the unit retirement studies. For each of the units analyzed, environmental control requirements and dates included in the analyses were based on the expected compliance requirements of final, proposed, and/or expected environmental rules and regulations.

A unique environmental capital and O&M spending schedule was developed for each retirement portfolio, with compliance retrofits required for the coal combustion residuals (CCR) and ELG rules. In Retirement Portfolio 1, NIPSCO also assumed that Schahfer Units 17 and 18 would require additional environmental upgrades associated with a selective catalytic reduction system, a de-watering system, and stack lining. NIPSCO also developed a hypothetical portfolio (Retirement Portfolio 4) that retains Schahfer 14 and 15 through 2028 with no ELG compliance spending, though this is not currently a viable ELG compliance pathway.

NIPSCO also included estimated costs to mitigate transmission related issues that would arise as a result of the various retirement combinations at Schahfer. An additional $79.8 million of capital expenditures was incorporated for transmission upgrades at the time of the Schahfer 17 and 18 retirement in any retirement portfolio. When all of Schahfer is retired, a total of $147 million in additional capital expenditures related to transmission upgrades has been incorporated. These estimates developed by NIPSCO transmission planning group are based on NERC transmission planning standards and incorporate the impact of the MISO retirement study process (Attachment Y)

Recovery of remaining depreciation expenses by 2030 has also been incorporated in the retirement analysis. NIPSCO has prudently ensured that each of its facilities has been ready and available to meet customer needs over the past several decades through appropriate capital investment and O&M expenditures. Upon retirement, due to this continued capital investment, there will be a remaining net book value associated with the generation assets. The retirement analysis assumes that when a unit is retired prior to end of life, it still recovers the return on and return of its net book value.

NIPSCO assumes that each unit continues to depreciate at the same blended rate of 4.60%, regardless of whether the unit has been retired or not. The unit continues to depreciate until its book value is equal to the negative "cost of removal" for each asset. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO electric depreciation studies. In addition to the "return of" (depreciation) the existing net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital, or "WACC.". Additionally, NIPSCO assumes that property and income tax will *not* be collected on the remaining net book value of the plant if it is retired.

9.1.6 Evaluation of Each Retirement Portfolio – Scorecard Metrics

NIPSCO developed a set of decision criteria objectives and metrics against which to evaluate the full set of retirement portfolios. The analysis was then conducted to quantify the performance of each portfolio against each scorecard metric. The following section describes each of the key objectives and metrics in more detail:

- Cost to Customer is measured by the overall net present value of revenue requirements ("NPVRR").

- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the most likely range of the distribution of outcomes. It is quantified by the 75th percentile of cost to customer in the stochastic analysis.

- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the by 95th percentile of cost to customer in the stochastic analysis.

- Reliability Risk assess NIPSCO's ability to confidently transition its portfolio of resources and maintain customer and system reliability. Reliability Risk considers the activities, timelines and risks of the MISO retirement process, transmission system and reliability upgrades, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at once. Reliability risk is a qualitative assessment made by NIPSCO of how orderly the transition would be from its current portfolio. It considers NIPSCO's ability to analyze, plan for and execute any transmission system upgrades and/or other equipment needed to ensure that customers' needs for reliability met.

- Other factors, such as the loss of work for employees, and the reduction of property tax base for surrounding communities also factored into NIPSCO's decision making process. While these do not directly impact power supply costs to customers, they are factors that should be included in the analyses. The employee metric is represented by the net impact on NiSource jobs at existing facilities, and the local economy metric is represented by the expected impact on local property taxes as compared to NIPSCO's 2016 IRP.

A summary of the decision criteria metrics is provided in Figure 9-3.

Figure 9-3: Scorecard Metrics for Retirement Analysis

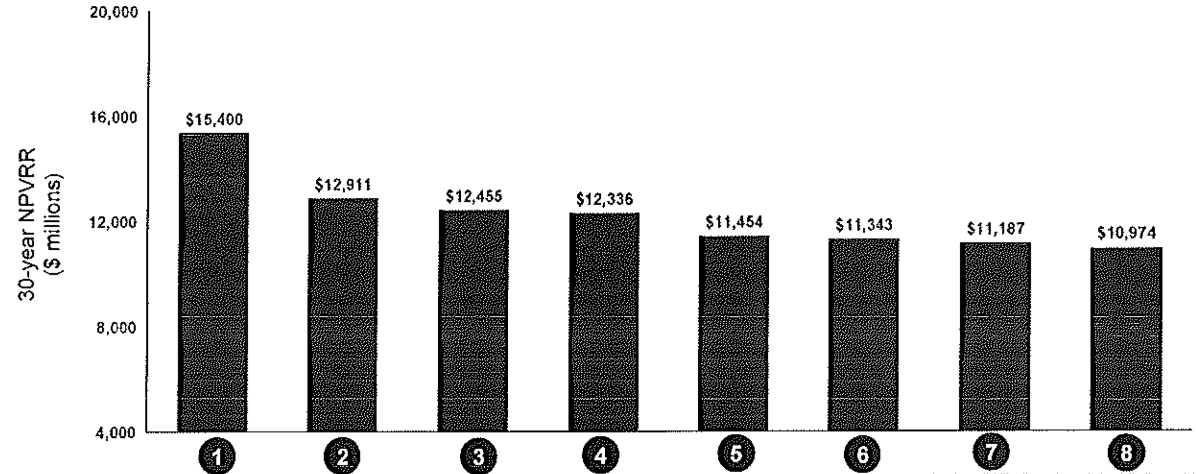
2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year net present value ("NPV") of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

9.1.7 Evaluation of Each Retirement Portfolio – Results

Base Case Cost Results

The eight retirement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Retirement Portfolio 8 (retiring all coal in 2023) was the least cost option, with a thirty-year NPVRR of just over $11 billion, while Retirement Portfolio 1 (keeping all existing coal units until 2035) had the highest costs, with an NPVRR of nearly $15.4 billion. Generally speaking, retiring more coal earlier resulted in a lower NPVRR. Figure 9-4 summarizes the cost results for each retirement portfolio under the Base Case, along with a summary of the cost premium for each option relative to Portfolio 8, which is least cost.

Figure 9-4: Cost to Customer Impacts – Retirement Portfolios



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr.17,18 (2023)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City 12 (2028) Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City 12 (2028) Schfr.17,18 (2021) Schfr.14,15 (2023)	Mich City 12 (2023) Schfr.17,18 (2023) Schfr.14,15 (2023)
Retain beyond 2023:	Mich. City. 12 Schfr.14,15,17,18	Mich. City. 12 Schfr.14,15	Mich. City. 12 Schfr.14,15	Mich. City. 12 (2035) Schfr.14,15	Mich. City. 12 (2035)	Mich. City. 12 (2028)	Mich. City. 12 (2028)	None
Delta from Least Cost:	$4,426M 40%	$1,937M 18%	$1,481M 13%	$1,361M 12%	$479M 4%	$369M 3%	$213M 2%	$0M

Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each retirement portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in 9-5, with additional details regarding the scenario results described below.

Figure 9-5: Cost to Customer across All Scenarios – Retirement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
1	15,400	17,557	11,598	15,030
2	12,911	14,271	9,642	12,758
3	12,455	13,304	9,479	12,291
4	12,336	13,184	9,359	12,171
5	11,454	12,298	8,474	11,245
6	11,343	12,084	8,428	11,125
7	11,187	11,820	8,351	11,023
8	10,974	11,688	8,079	10,745

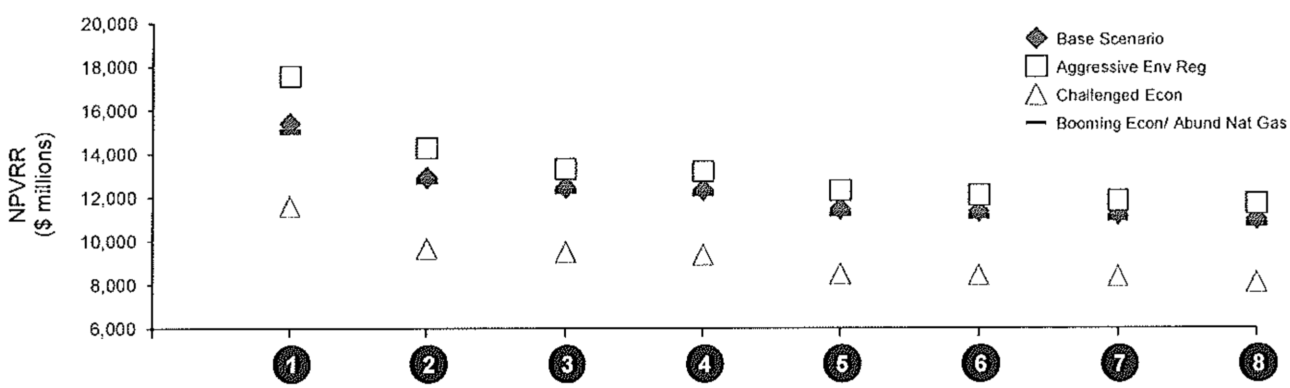
Under the Aggressive Environmental Regulation scenario, higher carbon prices drive higher portfolio costs, especially for those retirement portfolios that retain more coal capacity. The NPVRR of Retirement Portfolio 1 increases to about $17.5 billion, and the difference in cost between retaining all coal and retiring all coal in 2023 grows to about $6 billion. In addition, the costs associated with keeping Schahfer Units 14/15 beyond 2023 (Retirement Portfolio 2) rise considerably relative to the other options.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that retain more coal, but the overall costs are still lowest for Retirement Portfolio 8 (retiring all coal in 2023). While the savings associated with retiring coal are lower than those in the Base Case, the difference in cost between retaining all coal and retiring all coal in 2023 is still around $3.4 billion.

Under the Booming Economy & Abundant Natural Gas scenario, cost savings associated with coal retirements are similar to those under Base Case conditions, as low natural gas prices impact the coal units and the replacement renewable options similarly. The difference in cost between retaining all coal (Retirement Portfolio 1) and retiring all coal in 2023 (Retirement Portfolio 8) is about $4.2 billion, which is similar to the difference in the Base Case.

Overall, while coal retirement economics are relatively sensitive to carbon prices, the performance of the different retirement portfolios is less impacted by changes in natural gas prices, since the lowest-cost replacement option primarily comprises renewable resources. Thus, the relative savings associated with retiring coal grow under high carbon price conditions and fall when there is no price on carbon. However, under all market scenarios that were evaluated, there is significant savings associated with retiring more coal capacity. These results are summarized for each portfolio and each scenario in Figure 9-6.

Figure 9-6: NPVRR Summary across All Scenarios – Retirement Portfolios

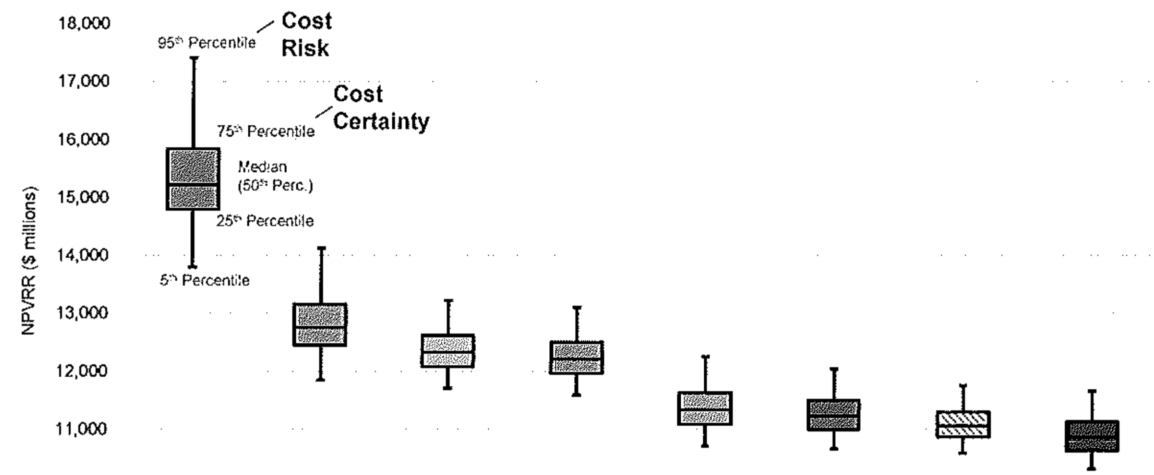


Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the retirement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. The stochastic analysis is used to further evaluate the risk of each of the retirement portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis. Overall, the results of the stochastic analysis suggest that retaining more coal in the portfolio increases risk, given that portfolios with more coal generally have a higher range of cost outcomes and higher NPVRR costs at the 75th percentile and the 95th percentile of the stochastic distribution.

Figure 9-7 presents a summary of the stochastic results for each of the retirement portfolios. This plot displays the distribution of outcomes for each retirement portfolio across the full 500 iterations that were analyzed in the stochastic analysis. The median value (or 50th percentile) is represented by the center line of each box, with the top and bottom of the box indicating the 75th and 25th percentiles, respectively. The lines above and below each box end at the 95th and 5th percentiles, respectively. NIPSCO's cost certainty metric is represented by the 75th percentile NPVRR value, while the cost risk metric is represented by the 95th percentile NPVRR value.

Figure 9-7: Summary of Stochastic Results – Retirement Portfolios

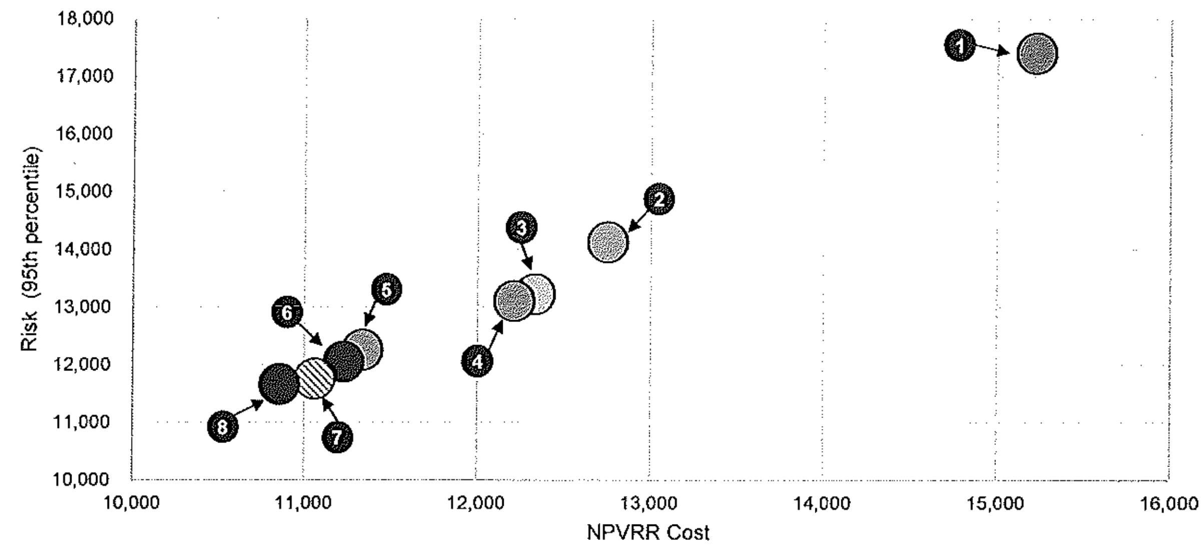


	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr.17,18 (2023)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City.12 (2028) Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City.12 (2028) Schfr.17,18 (2021) Schfr.14,15 (2023)	Mich City.12 (2023) Schfr.17,18 (2023) Schfr.14,15 (2023)
Retain beyond 2023:	Mich. City 12 Schfr.14,15,17,18	Mich. City 12 Schfr.14,15	Mich. City 12 Schfr.14,15	Mich. City 12 Schfr.14,15	Mich. City 12 (2035)	Mich. City 12 (2028)	Mich. City 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,708 42.3%	+$2,026 18.2%	+$1,490 13.4%	+$1,370 12.3%	+$502 4.5%	+$372 3.3%	+$163 1.5%	- $ - %
Delta from Lowest Cost Risk	+$5,750 49.3%	+$2,467 21.2%	+$1,569 13.5%	+$1,449 12.4%	+$596 5.1%	+$389 3.3%	+$93 0.8%	- $ - %

Overall, portfolios that hold more coal not only tend to be higher in median cost, but also have a broader range of outcomes due to uncertainties associated with future coal plant dispatch and relatively significant carbon and commodity price uncertainty. Meanwhile, the portfolios that retire more coal and replace that capacity with fixed-price renewable resources are less subject to market price and dispatch uncertainties. Retirement Portfolio 1 (keeping all existing coal units until 2035) has a cost certainty value that is around $4.6 billion higher than that of Portfolio 8 (retiring all coal in 2023), and a cost risk value that is around $5.7 billion higher. Generally speaking the portfolios that replace more coal with more DSM and renewables result in lower NPVRR for both risk metrics.

Another way to examine the cost and risk performance of the various retirement portfolio options is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-8, which shows that higher costs are generally associated with higher risks, as measured through the 95[th] percentile outcome. At the 95[th] percentile, portfolios that hold more coal are exposed to the risk of higher carbon prices, as well as potentially low power prices and reduced dispatch in the market. Thus, they are considered riskier than the retirement portfolios that limit such exposure with resources that have more certain dispatch and no variable costs (renewables) over the long-term.

Figure 9-8: Summary Cost and Tail Risk – Retirement Portfolios



Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight retirement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on portfolio flexibility, NIPSCO employees, and the local economy, as described above.

Figure 9-9: Retirement Portfolio Scorecard

	1	2	3	4	5	6 (Preferred Retirement Path)	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr.17,18 (2023)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2028)	Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City.12 (2028) Schfr.17,18 (2023) Schfr.14,15 (2023)	Mich City.12 (2028) Schfr.17,18 (2021) Schfr.14,15 (2023)	Mich City.12 (2023) Schfr.17,18 (2023) Schfr.14,15 (2023)
Retain beyond 2023:	Mich. City 12 Schfr.14,15,17,18	Mich. City 12 Schfr.14,15	Mich. City 12 Schfr.14,15	Mich. City 12 Schfr.14,15	Mich. City 12 (2035)	Mich. City 12 (2028)	Mich. City 12 (2028)	None
Env. Compliance	CCR ELG non-ZLD	CCR ELG non-ZLD	CCR ELG non-ZLD	CCR ELG Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,362 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,703 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

Coal-to-Gas Conversion

As part of the retirement analysis, NIPSCO also evaluated the cost-effectiveness of converting one or two units at Schahfer to natural gas. The key assumptions for this analysis, including the operational parameters for the converted units and the costs associated with conversion and ongoing operations, are documented in Section 4. In developing this analysis, NIPSCO started with the Retirement Portfolio 6 and evaluated whether converting Schahfer 17/18 instead of replacing the capacity with the lowest-cost resources from the optimized All-Source RFP analysis was higher or lower cost. This analysis was performed for the conversion of both Units 17 and 18 and for just Unit 17 across all four market scenarios.

Across all scenarios coal to gas conversion is not a viable capacity alternative., Converting both Units 17 and 18 was projected to cost customers between $540 million to $1.04 billion more on a 30-year NPVRR basis than retirement and replacement of the units with economically optimized selections from the All-Source RFP results. This is shown in Figure 9-10. Converting a single unit was projected to cost customers between $230 million and $450 million more than retirement and replacement with economically optimized selections from the All-Source RFP results, as shown in Figure 9-11. While the conversion portfolio's economics improved under lower natural gas price and CO_2 price conditions (the Challenged Economy and Booming Economy/ Abundant Natural Gas scenarios), it was still significantly higher cost across all scenarios.

Figure 9-10: Coal-to-Gas Conversion Analysis Results – Two Units

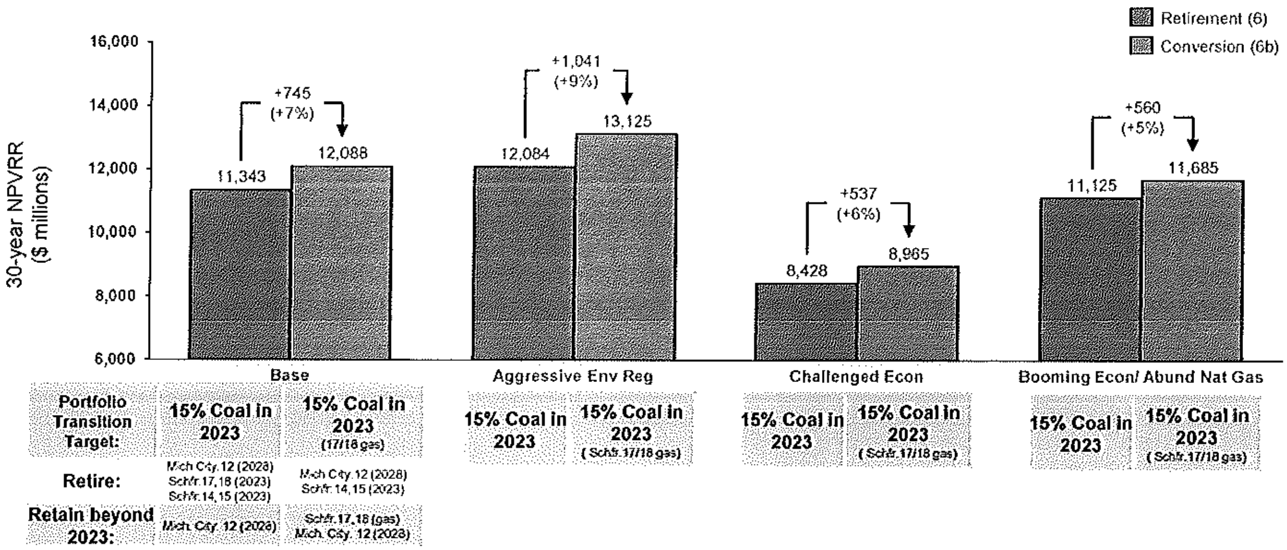
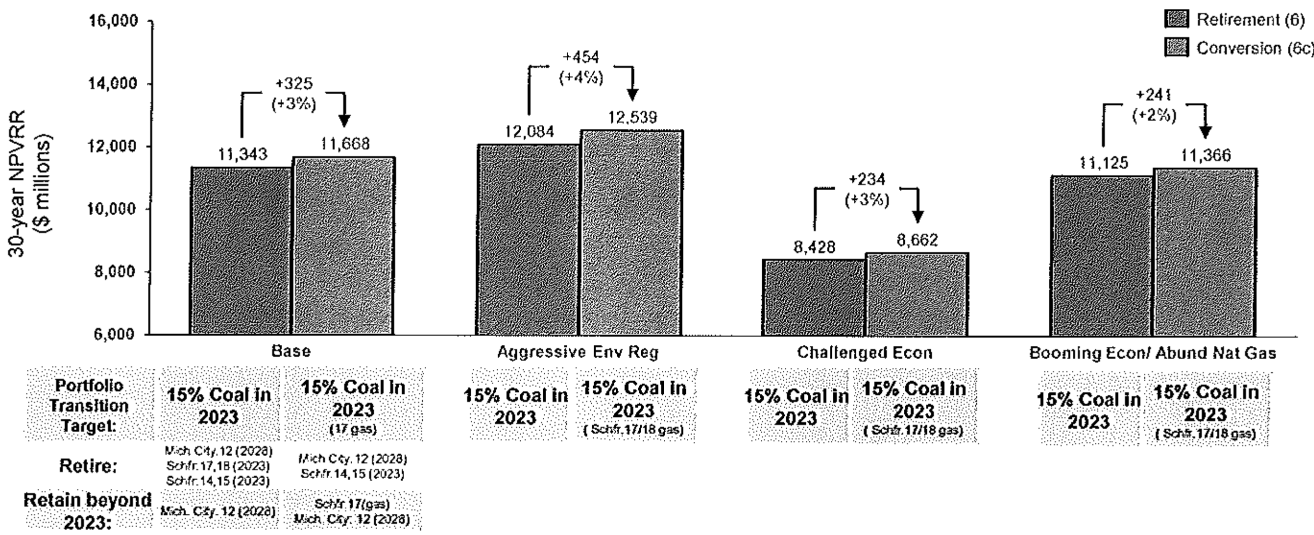


Figure 9-11: Coal-to-Gas Conversion Analysis Results – One Unit (Schahfer 17)



9.1.8 Preferred Retirement Portfolio

Retirement Portfolio 6 has been determined to be the most viable retirement pathway for NIPSCO, providing significant cost savings versus the status quo and offering an acceptable outcome for portfolio flexibility and with regard to the impact on employees and the local economy. This retirement portfolio retires all four units at Schahfer in 2023 and retires Michigan City in 2028.

Combination 6 was selected because it was the lowest cost option that held acceptable reliability risk for customers and the system. The analysis shows that Combination 6 saves customers over $1.5 billion relative to NIPSCO's 2016 IRP preferred plan. From a reliability risk standpoint, it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. While the transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek, a CCGT, even longer. Both are dispatchable units that can be used to support the transition while we implement the replacement path. Another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate versus locking the entire transition in at once.

It is anticipated that NIPSCO's 2018 IRP preferred retirement path will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC TPL standards, NIPSCO Planning criteria, and MISO requirements. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y). As part of the retirement analysis, NIPSCO transmission planning group performed preliminary studies to evaluate the impact of the 2018 IRP preferred retirement path that calls for the retirements of Schahfer units 14,15,17,18 and replacement with primarily wind and solar/storage resources in central and southern Indiana by 2023. The studies identified a number of circuits on the NIPSCO transmission system that will likely violate NERC planning standards requirements. Once NIPSCO files its Attachment Y, making the retirement of Schahfer's units 14, 15, 17, 18 official with MISO, any violations found in MISO's analyses in the Attachment Y process and in NIPSCO's subsequent annual transmission planning analyses would need to be mitigated prior to the units' retirement in 2023. The mitigation of those issues consist of 5 separate projects to rebuild over 47 miles of transmission lines and to add a reactive power source to support system voltage. The initial high level estimated cost of the projects is $150 million, which is included in the retirement analysis.

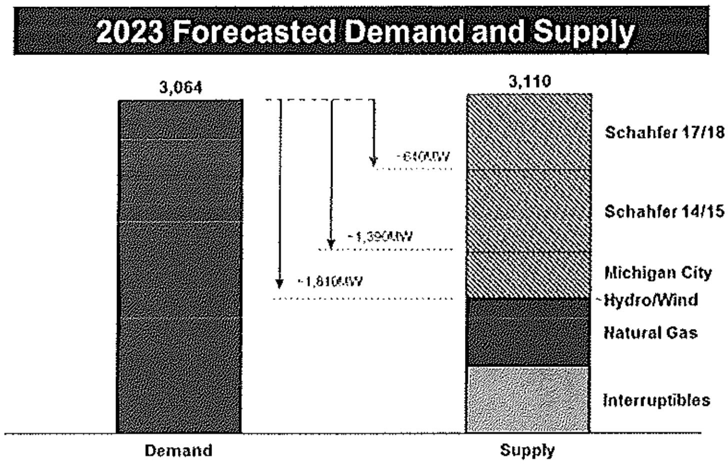
Initial estimates indicated that construction of these projects is anticipated to take until late 2022, early 2023 to complete. The projects are complex to engineer and construct because they require planned outages that need to be coordinated with MISO and PJM, as all of the projects impact PJM's system operation (reliability and markets). Furthermore, some of the rebuild projects are in urban areas or environmentally sensitive terrain like wetlands which carry additional environmental and other risks. There could also be potential outage conflicts with previously planned infrastructure improvement projects not associated with retirements.

Starting in early 2019, NIPSCO will begin engineering the projects and will begin initial construction and outage planning activities. Construction is expected to begin in early 2020. All of the projects are anticipated to be placed in service prior to the units being retired.

With its preferred retirement combination, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. Although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty and lower cost risk over alternatives that hold more coal capacity. This option balances other non-economic considerations such as portfolio flexibility, employee and property tax impacts.

Under such a portfolio, a capacity gap of around 1,300 MW will open up in 2023, as shown in Figure 9-12, which summarizes current capacity resources against NIPSCO's Base Case load forecast, inclusive of reserve margin requirements. This capacity gap is the subject of the replacement analysis that is described next.

Figure 9-12: Future Capacity Need under Preferred Retirement Portfolio



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer 17/18	(640)
Retire Schahfer 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

9.2 Replacement Analysis

9.2.1 Process Overview

NIPSCO has evaluated a range of potential resource replacement options to fill the capacity gap that would develop under Retirement Portfolio 6. The replacement analysis was performed in a similar manner to the retirement analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for ownership and commitment duration and portfolio diversity captured via the emissions profile of resources.

- Develop specific replacement portfolios within each concept using IRP optimization tools and data from the All-Source RFP.

- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this Section).
- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio.

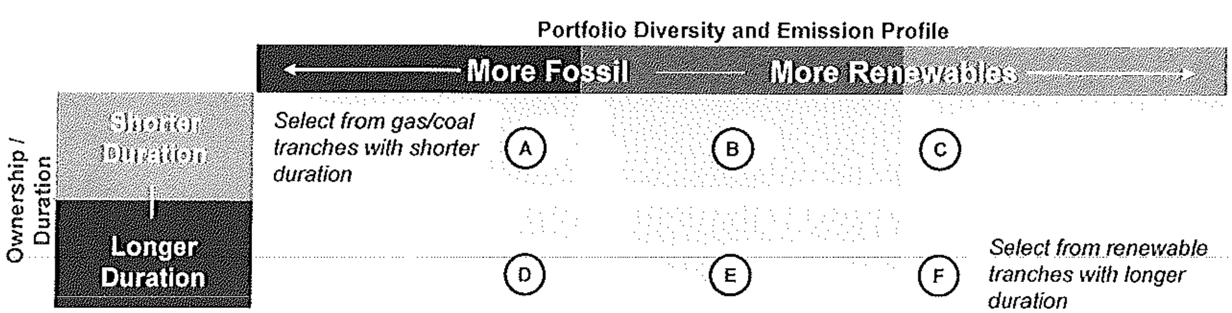
9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on several key planning considerations. The first consideration was structured around the commitment duration being assumed by NIPSCO under each potential portfolio option. Duration is defined as the length of time commitment to a specific resource; shorter duration resources, generally in the form of short-term PPAs, can partially mitigate industrial risk since they do not lock-in a commitment over the very long term. Longer duration resources, on the other hand, generally in the form of longer-duration PPAs or owned assets, tend to have commitments of twenty years or more. By developing portfolios across a range of duration commitments, NIPSCO was able to evaluate the costs and risks associated with different resource procurement strategies.

The second consideration was structured around the potential portfolio's diversity, specifically related to carbon dioxide emission intensity. NIPSCO currently has a portfolio with a high concentration of coal generation, and portfolio concepts were developed with varying levels of fossil and renewable resource replacements in order to evaluate the costs and risks associated with strategies that align with NIPSCO's environmental targets and various stakeholder interests.

After reviewing the type of replacement resources available from the All-Source RFP (*See* Section 4.9.2 for more detail.), NIPSCO determined that portfolio concepts could feasibly be developed across two duration levels (shorter and longer) and three diversity levels (all fossil replacements, a mix of fossil and renewable replacements, and all renewable replacements). Thus six difference concepts were identified for more detailed portfolio development, as shown in Figure 9-13. These portfolios are referred to as Portfolios A-F throughout the rest of this Section.

Figure 9-13: Replacement Consideration Matrix



9.2.3 Development of Specific Replacement Portfolios

Based on the six replacement concepts, NIPSCO then developed specific portfolios that met the desired considerations. This was done through the Aurora model's portfolio optimization capability, which allows the user to specify a set of options and portfolio constraints that drive towards a least cost revenue requirement solution.

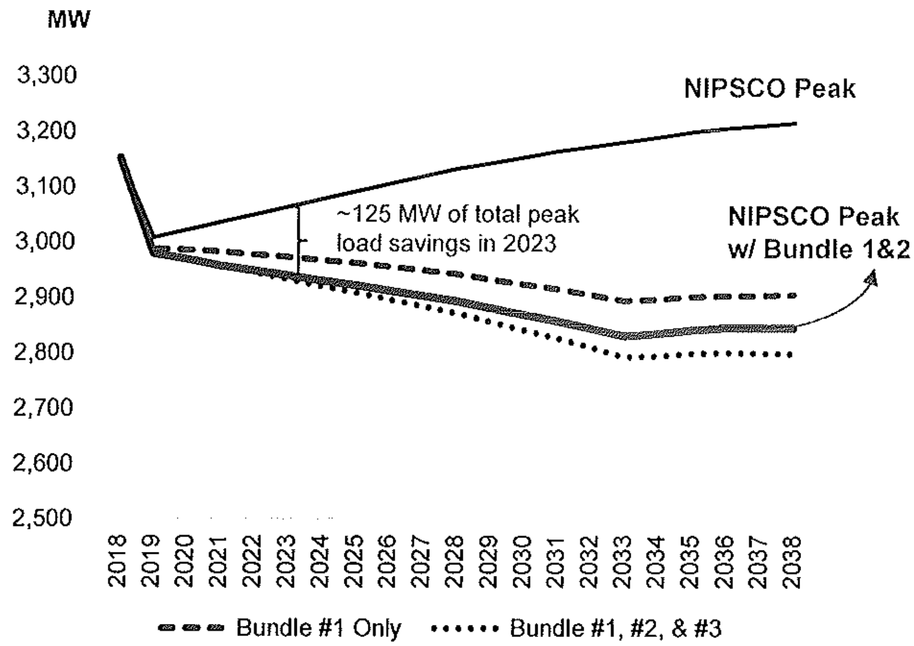
DSM Portfolio Selection

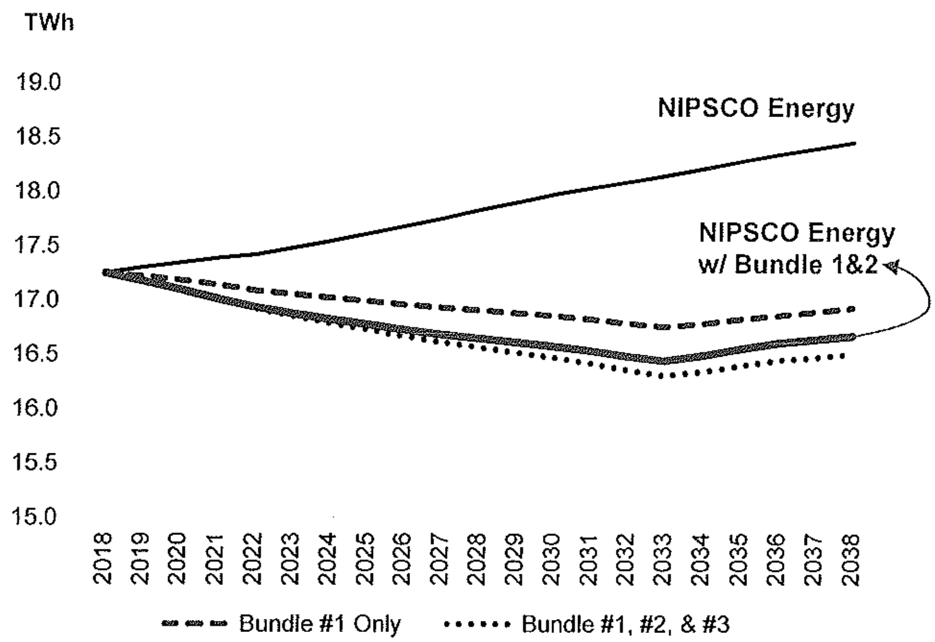
NIPSCO allowed demand side management (DSM) and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in Section 5, three separate DSM bundles were developed by GDS Associates for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios. Figure 9-14 summarizes the peak and average DSM MW that were selected by bundles in 2023 (the year of the capacity gap under Retirement Portfolio 6) and in 2038 (the final year of the fundamental modeling horizon). Figure 9-15 summarizes the impacts of the various DSM bundles over time, indicating the expected savings for peak load and total energy sales with Bundles 1 and 2 selected.

Figure 9-14: DSM Selection in 2023 and by 2038

DSM Bundle #	Weighted Avg. Cost ($/MWh)	MW Selected by 2023 (Peak / Average)	MW Selected by 2038 (Peak / Average)
1	17	91 / 48	310 / 174
2	23	34 / 20	60 / 29
3	159	0 / 0	0 / 0

Figure 9-15: Selected DSM Resources across Replacement Portfolios (Peak and Energy)





All-Source RFP Resource Selection

Beyond DSM selection, NIPSCO then evaluated the candidate resource options from the All-Source RFP to be selected for each of the six replacement portfolio concepts. In performing this analysis, the Aurora optimization model was constrained differently for each portfolio in order to meet the duration and diversity targets. Along the duration axis, for Portfolios A, B, and C, 400 MW of short-term MISO market purchases were assumed for each portfolio to offer a minimal duration commitment that could protect against industrial load loss. After that, short-term contract options were available first, followed by longer-term contracts when shorter-term resources were exhausted. For Portfolios D, E, and F, long-term contracts and asset ownership options were available, with no short-term PPAs eligible to be selected. Along the diversity axis, Portfolios A and D only had access to fossil-fired resources, while Portfolios C and F only had access to renewable and storage resources. Portfolios B and E were allowed to select a portion of the lowest cost fossil resources within the relevant duration concept, with the remaining capacity gap filled with renewables.

Figure 9-16 summarizes the UCAP MW selected by All-Source RFP tranche (*See* Section 4 for more detail on All-Source RFP tranche development.) across all six portfolio concepts, and Figure 9-17 summarizes the total incremental resource replacement additions in 2023 by type. The preferred fossil resources were CCGT, along with a small, fossil-based system power contract, while the preferred renewable resources were wind projects, followed by solar and solar plus storage options. Although the replacement portfolio selection process is not reflective of a specific, preferred action plan, it was able to construct a range of portfolio strategy concepts to be fully evaluated with the IRP analysis tools and against the full scorecard of key criteria metrics. A summary of NIPSCO's potential capacity position by fuel type across all of the six replacement portfolios is shown in Figure 9-18.

Figure 9-16: Selected Resource Tranches by Replacement Portfolio

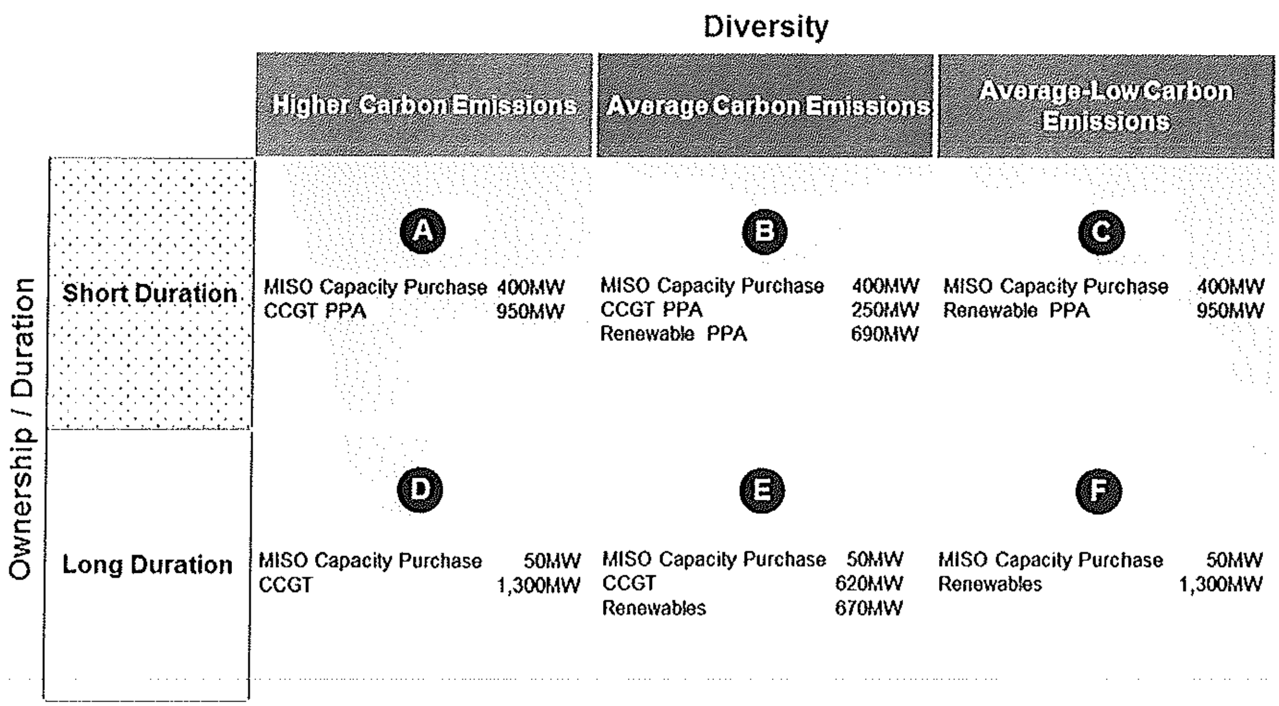


Figure 9-17: 2023 Incremental Replacement Resources by Portfolio (UCAP MW)

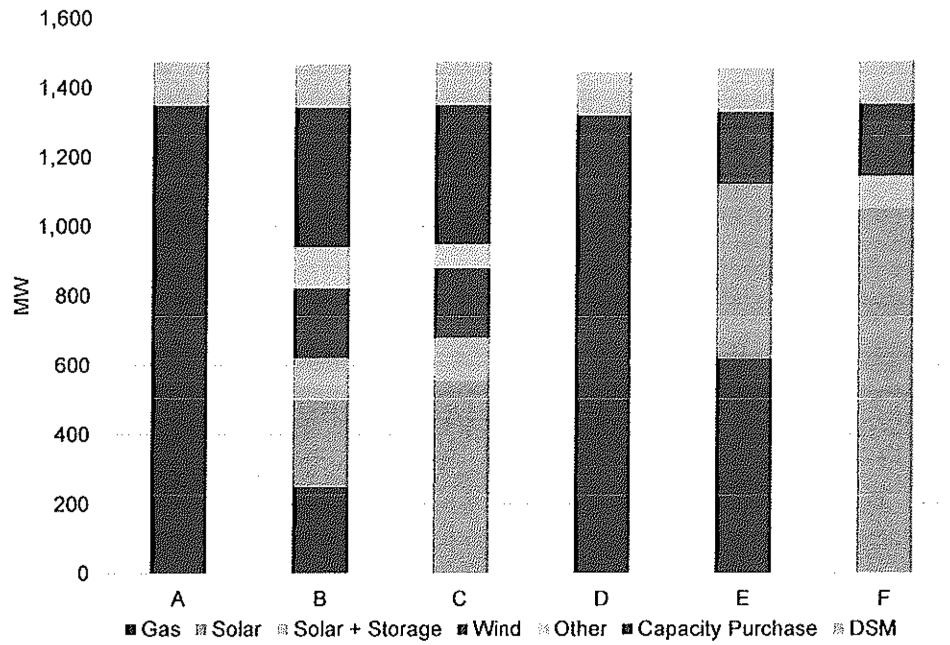
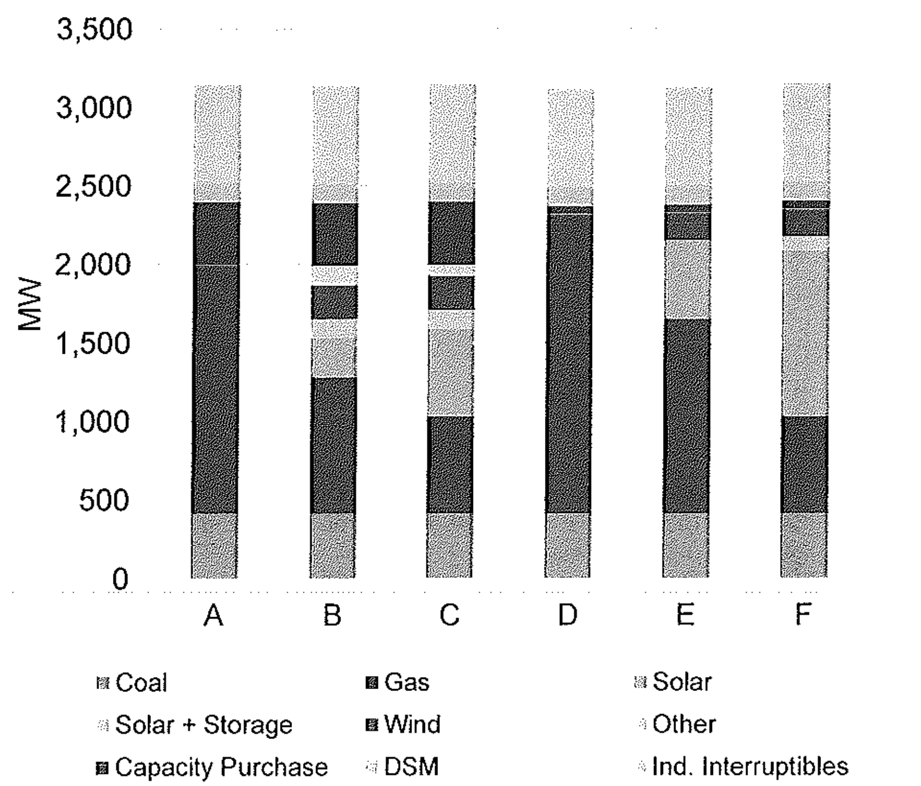


Figure 9-18: 2023 Total Projected Capacity Mix by Portfolio (UCAP MW)



9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the retirement analysis, NIPSCO developed a scorecard of criteria and key metrics associated with the replacement analysis. Many of the metrics are the same, with two additions: fuel security, defined as the percentage of capacity sourced from resources other than natural gas, and environmental emission intensity, defined as the total carbon emissions in 2030 from the full generation portfolio. A summary of the decision criteria metrics for the replacement analysis is provided in Figure 9-19.

Figure 9-19: Scorecard Metrics for Replacement Analysis

2018 Replacement Scorecard

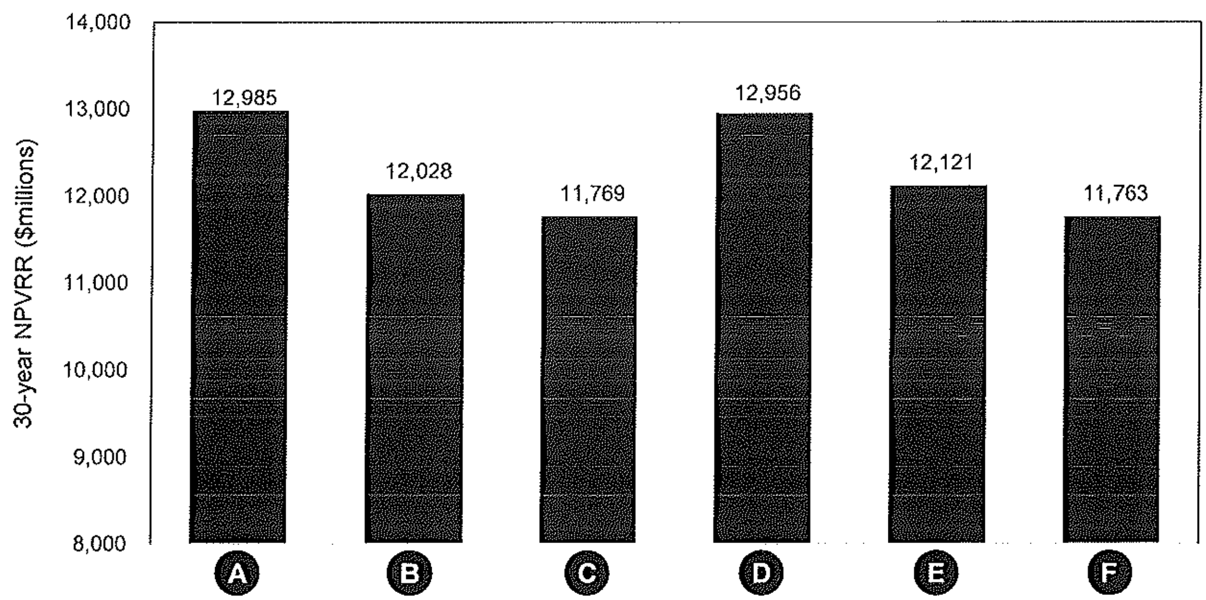
Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 ICAP MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of CO_2) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

9.2.5 Evaluation of Replacement Portfolios – Results

Base Case Cost Results

The six replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Replacement Portfolio F (long-duration renewables) was the least cost option, with Replacement Portfolio C (short-duration renewables) only $6 million higher on an NPVRR basis. The portfolios with only natural gas and other fossil resource additions (Replacement Portfolios A and D) are highest cost, while portfolios with a mix of gas and renewable additions (Replacement Portfolios B and E) have a cost premium of between $250 and $350 million when compared to Portfolio F. Figure 9-20 summarizes the results for the each replacement portfolio under Base Case conditions.

Figure 9-20: Cost to Customer Impacts – Replacement Portfolios



Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-21, with additional details regarding the scenario results described below.

Figure 9-21: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
A	12,985	14,476	9,496	12,167
B	12,028	12,948	8,985	11,699
C	11,769	12,675	8,740	11,475
D	12,956	14,426	9,463	12,097
E	12,121	12,970	9,102	11,756
F	11,763	12,424	8,905	11,585

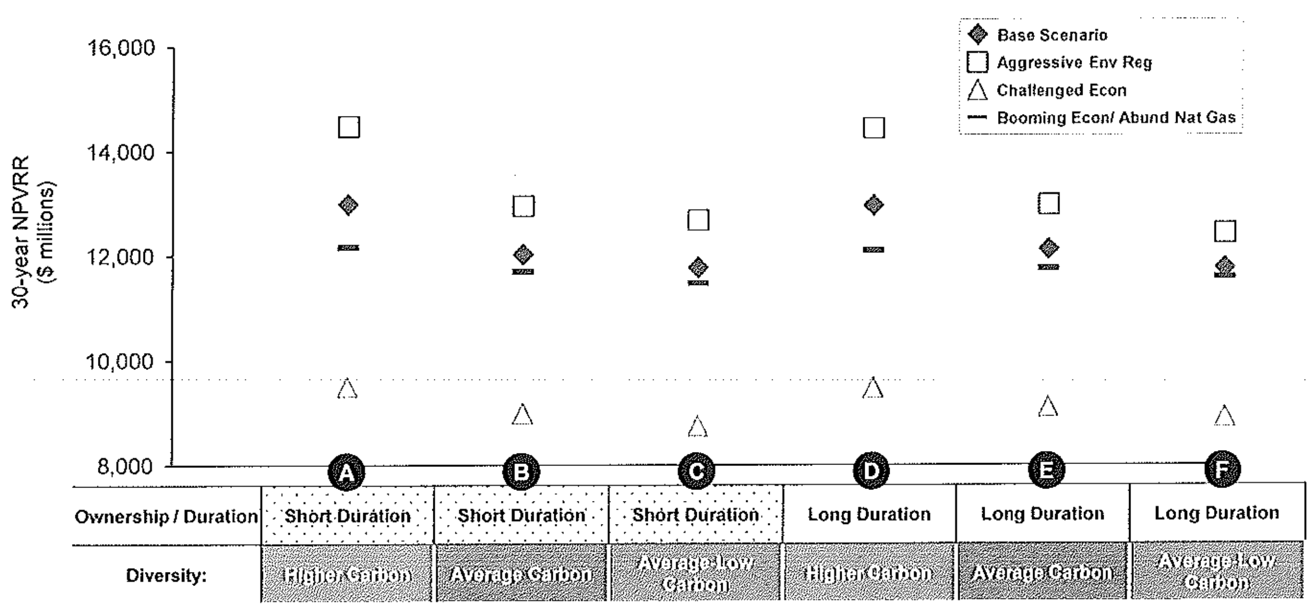
Under the Aggressive Environmental Regulation scenario, higher carbon prices and higher natural gas prices drive higher portfolio costs overall, but more so for the portfolios with significant natural gas capacity additions (Portfolios A and D). Meanwhile, the renewable dominant portfolios (Portfolios C and F) see change in costs to a lesser degree, given that most costs associated with the renewable resource additions are fixed in nature. For example, the NPVRR for Portfolio D increases by nearly $1.5 billion versus the Base Case, while the NPVRR for Portfolio F increases by less than $700 million. In addition, the shorter-duration portfolios with more exposure to the market perform relatively worse under the Aggressive Environmental Regulation scenario due to the fact that market prices are significantly higher. While Portfolios F and C are nearly identical in cost in the Base Case, Portfolio F has an NPVRR that is $250 million lower than Portfolio C's in this scenario.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that include more natural gas capacity, but the renewable-only portfolios are still lowest cost. Furthermore, given that market prices are low and given that NIPSCO load is lower, the short-duration renewable concept (Portfolio C) performs best in this scenario, since its market exposure is significantly reduced. In fact, Portfolio C has a lower NPVRR than Portfolio F by about $160 million.

Under the Booming Economy & Abundant Natural Gas scenario, low natural gas prices improve the relative position of the portfolios with more natural gas capacity, as fuel costs are lower and natural gas combined cycle dispatch is higher. For example, the NPVRR of Portfolio D (long-duration natural gas) declines by about $860 million relative to the Base Case in this scenario, while the NPVRR of Portfolio F (long-duration renewables) declines by only about $180 million. However, although Portfolios D and E are much closer in Cost to Portfolio F, the all-renewables options are still the least expensive alternative. Portfolio C is slightly lower cost overall, due to lower market prices reducing its MISO market exposure relative to Portfolio F.

Overall, while the relative economics of fossil and renewable resource replacement options are impacted by changes in carbon prices, natural gas prices, and MISO market power prices, the lowest-cost replacement option is always dominated by renewable resources. When market prices are low and when NIPSCO load is low, a shorter-duration renewable strategy is lower cost, while a longer-duration renewable portfolio performs best in the Base Case and when market prices are higher. These results are summarized for each portfolio and each scenario in Figure 9-22.

Figure 9-22: NPVRR Summary across All Scenarios – Replacement Portfolios

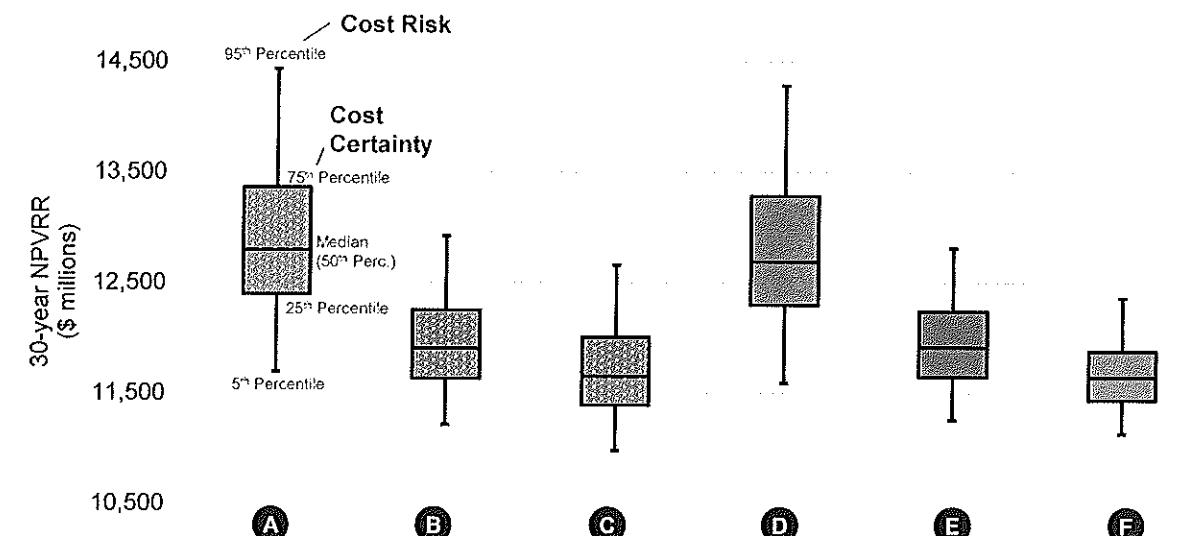


Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. As in the retirement analysis, the stochastic assessment is used to further evaluate the risk of each of the portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis.

Figure 9-23 presents a summary of the stochastic results for each of the replacement portfolios. Overall, although the introduction of stochastic price volatility impacts the natural gas and renewable resource elements in each portfolio differently, Portfolio F (long-duration renewables) has the lowest median cost, and also the lowest cost at the 75th and 95th percentiles.

Figure 9-23: Summary of Stochastic Results – Replacement Portfolios



	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Delta from Lowest Median Cost	$1,147 9.8%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest Cost Certainty	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	**$0 0.0%**
Delta from Lowest Cost Risk	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	**$0 0.0%**

On average, the median difference in NPVRR between the renewable-only portfolios and those that have some natural gas capacity goes down, meaning that natural gas options look relatively better in the stochastics when compared to their performance in deterministic Base Case.

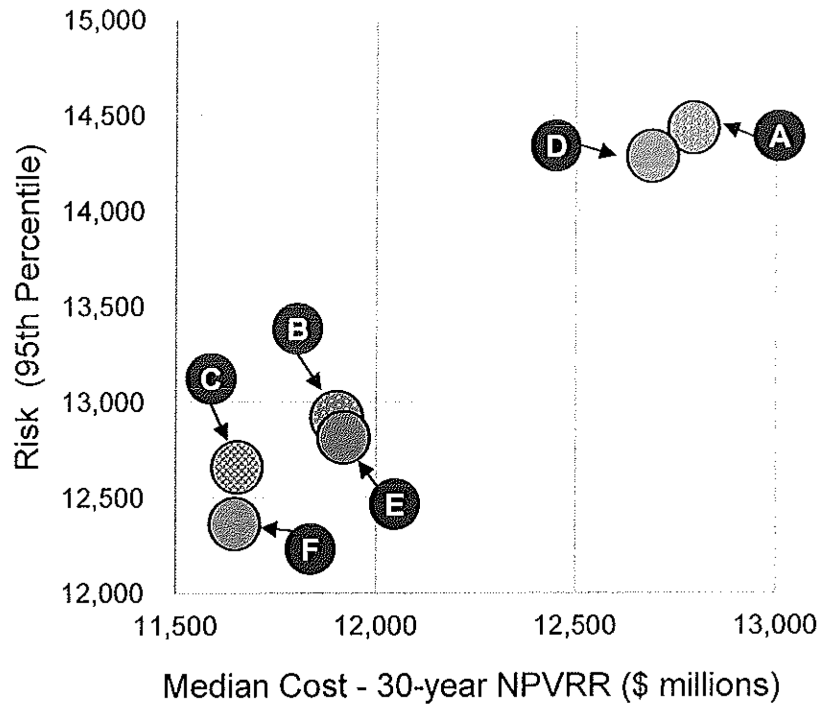
This is because natural gas plants can take advantage of potential low gas price outcomes and can flexibly dispatch in response to changing prices in a volatile market, while renewable costs and dispatch are generally fixed. However, this small improvement in NPVRR for natural gas portfolios across the stochastic distribution does not outweigh the overall cost benefits associated with incorporating fixed price renewable assets into the portfolio.

Although more favorable market conditions for gas resources are incorporated into the stochastic assessment, as more natural gas capacity is added to the portfolio, costs and risks increase. This is due to the fact that natural gas capacity is more exposed to gas price volatility on the upside, which impacts both dispatch and the costs of operation. Although gas-dominant portfolios perform better when gas prices are low, they become heavily exposed to conditions with higher gas and carbon prices, resulting in significantly higher portfolio costs than those options that include more renewables. Portfolio F (long-duration renewables) has a cost certainty value that is around \$1.4 billion lower than that of Portfolio D (long-duration CCGT) and \$360 million lower than that of Portfolio E (long-duration mix), and a cost risk value that is around \$1.9 billion lower than Portfolio D and \$450 million lower than Portfolio E.

The longer-duration renewable portfolio (F) also performs better on the risk metrics than the shorter-duration renewable portfolio (C). This is due to the fact that Portfolio C includes 400 MW of MISO market purchases, resulting in higher costs under conditions with higher carbon, fuel, and power prices. This drives the width of Portfolio C's distribution higher. Although Portfolio F and Portfolio C have nearly identical NPVRRs at the median cost level, Portfolio F is about \$125 million lower in cost at the 75th percentile and nearly \$300 million lower in cost at the 95th percentile.

Another way to examine the cost and risk performance is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-24, which shows that higher costs are generally associated with higher risks, as measured through the 95th percentile outcome. At the 95th percentile, portfolios with more natural gas capacity are exposed to the risk of higher gas prices and higher carbon prices, as well as potentially reduced dispatch in the market. More fixed-price renewable resources generally result in lower tail risk overall. The difference in risk profile between Portfolios C and F is also evident in this figure. Although both portfolios have nearly the same median cost (x-axis), F has significantly lower 95th percentile risk (y-axis).

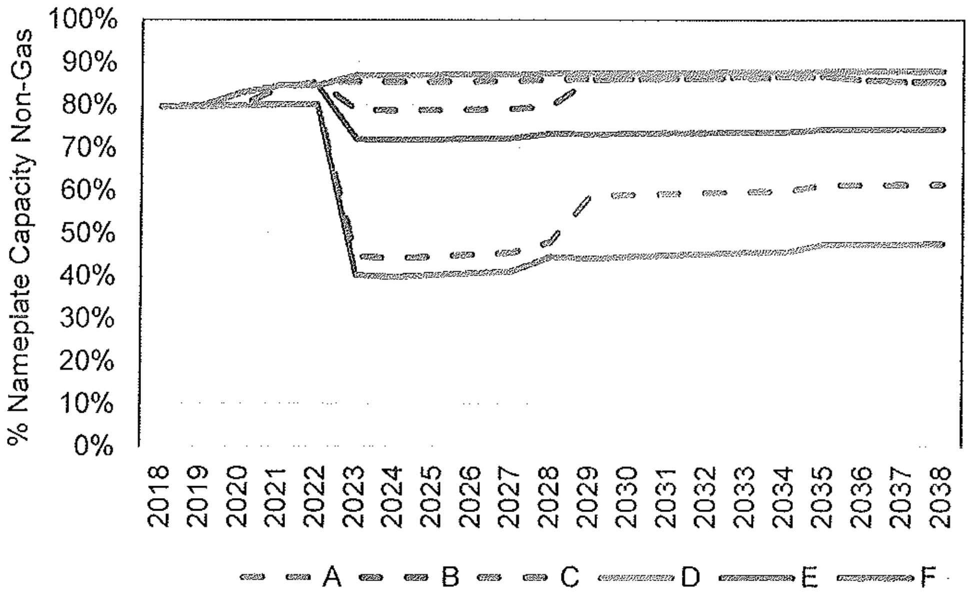
Figure 9-24: Summary Cost and Tail Risk – Replacement Portfolios



Additional Scorecard Metric Results

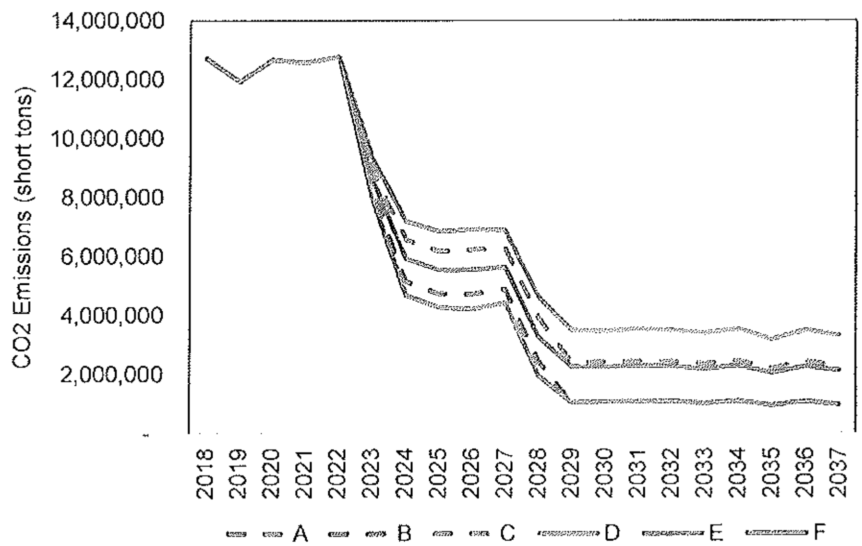
NIPSCO has identified fuel security as an important metric in its integrated scorecard assessment. Fuel security has been defined as the percentage of total nameplate capacity that is sourced from non-natural gas resources. A summary projection of this metric over time for each of the six replacement portfolios is shown in Figure 9-25. As is shown, after the potential retirement of coal capacity in 2023, Portfolios A and D would have less than 50% of their capacity comprised of non-gas resources, while Portfolios C and F would be closer to 90% for this metric. For purposes of the scorecard, 2025 is used as the benchmark year.

Figure 9-25: Percent of Nameplate Capacity that is Non-Gas for Replacement Portfolios



As an environmental stewardship benchmark, NIPSCO has identified CO2 emissions has an important scorecard metric. While all replacement portfolios would expect to realize significant CO2 emission reductions with the retirement of coal capacity in 2023 and 2028, differences in long term emissions are dependent on whether the resource replacements are renewable or natural gas-fired. Figure 9-26 summarizes the projected CO2 emissions over time for all six replacement portfolios, showing that the renewable-only options are lower over the long-term.

Figure 9-26: Projected CO2 Emissions over Time for Replacement Portfolios



Scorecard Summary

Figure 9-27 presents a summary of all scorecard metrics for each of the six replacement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on fuel security, carbon emissions, NIPSCO employees, and the local economy.

Figure 9-27: Replacement Portfolio Scorecard

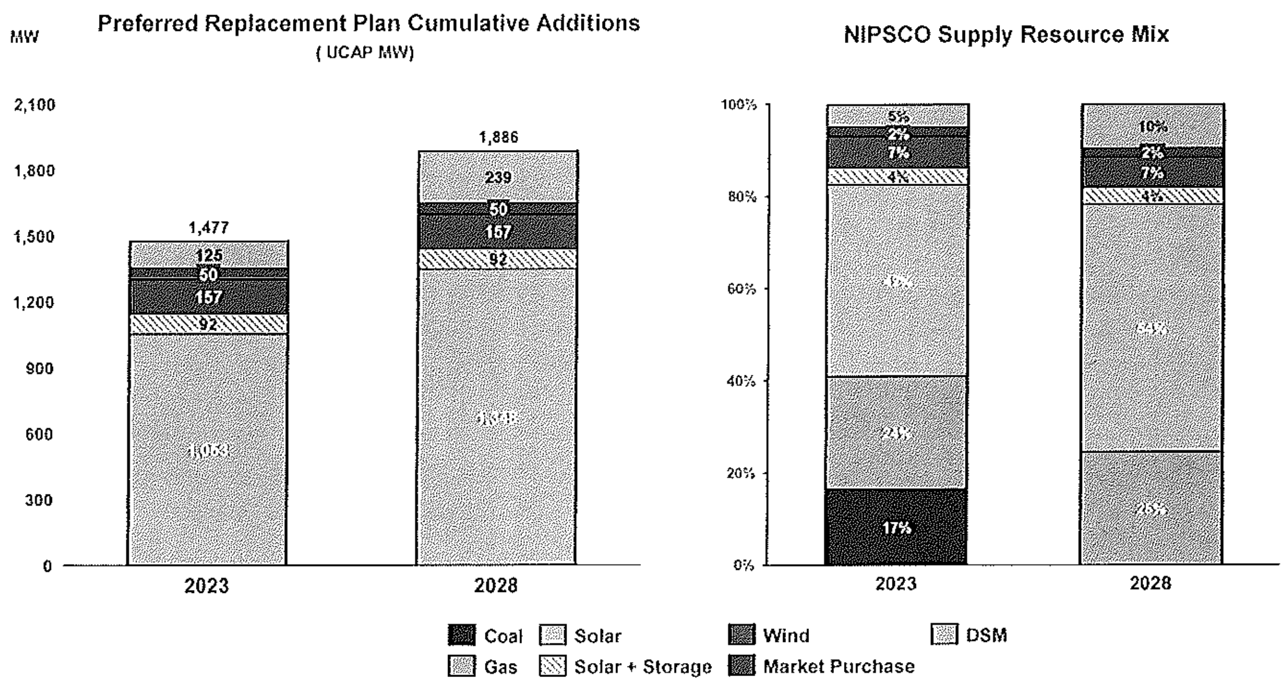
	A	B	C	D	E	F (Preferred Replacement Path)
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769 $6 0.1%	$12,956 $1,192 10.1%	$12,121 $357 3.0%	$11,763 $0 0.0%
Cost Certainty delta from least	$13,360 $1,477 12.4%	$12,254 $371 3.1%	$12,007 $124 1.0%	$13,286 $1,403 11.8%	$12,245 $362 3.0%	$11,883 $0 0.0%
Cost Risk delta from least	$14,431 $2,067 16.7%	$12,922 $559 4.5%	$12,661 $297 2.4%	$14,284 $1,920 15.5%	$12,815 $452 3.7%	$12,364 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	← Dependent on project selection and location; currently under evaluation →					

9.3 Preferred Replacement Portfolio

The replacement scorecard shown in Figure 9-27 shows that replacement portfolios with renewables are more cost effective than portfolios without renewables. Additionally, portfolios with more renewables provide greater amounts of CO2 emissions reduction and provide the greatest amount of fuel security.

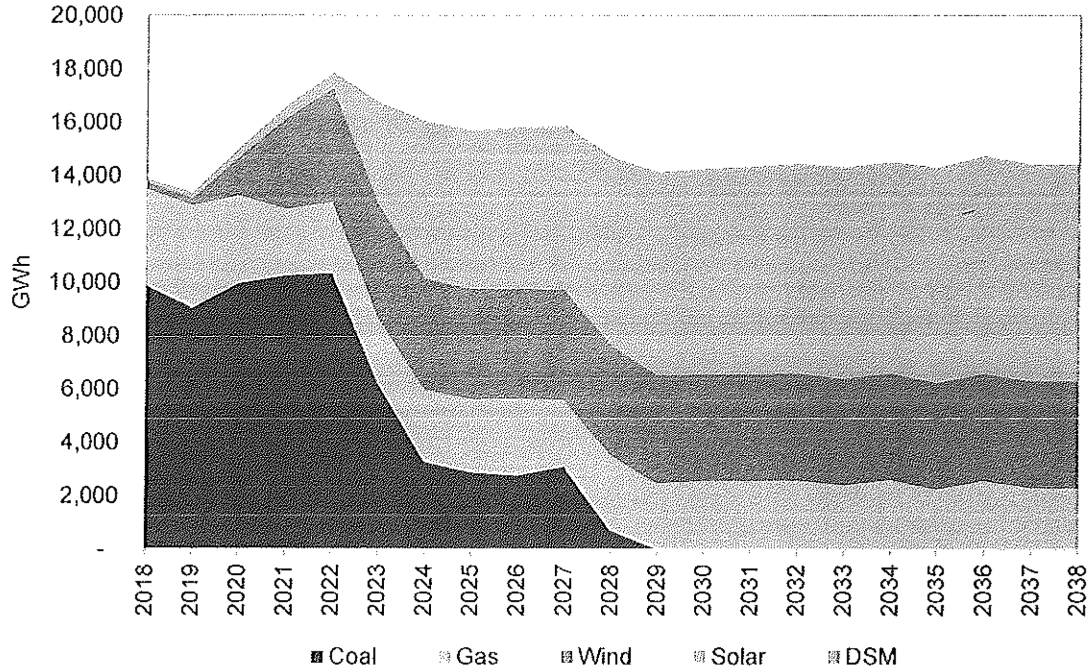
NIPSCO has selected replacement Portfolio F as the preferred plan. This portfolio calls for the addition of a mix of wind, solar, battery storage, market purchases and DSM resources over time. Figure 9-29 shows the NIPSCO preferred plan *incremental* additions and NIPSCO's overall projected capacity supply mix at the end of 2023 and 2028.

Figure 9-28: Preferred Plan Capacity Mix over Time



Over the twenty-year planning horizon, NIPSCO's generation mix is projected to shift significantly from coal to renewables. As shown in Figure 9-29, renewable generation is expected to increase with the acquisition of wind resources between 2020 and 2022 and solar resources thereafter. During this time period, coal generation is expected to decline to zero, while gas generation is projected to be relatively stable. Under this portfolio, NIPSCO will be supplied primarily by renewable resources (wind and solar) over the long-term, with meaningful natural gas and DSM contributions. Market purchases would be expected to meet the remainder of the requirements, but are dependent on renewable operations and the details of future resource decisions that are be made by NIPSCO in the coming years.

Figure 9-29: Preferred Portfolio Energy Mix

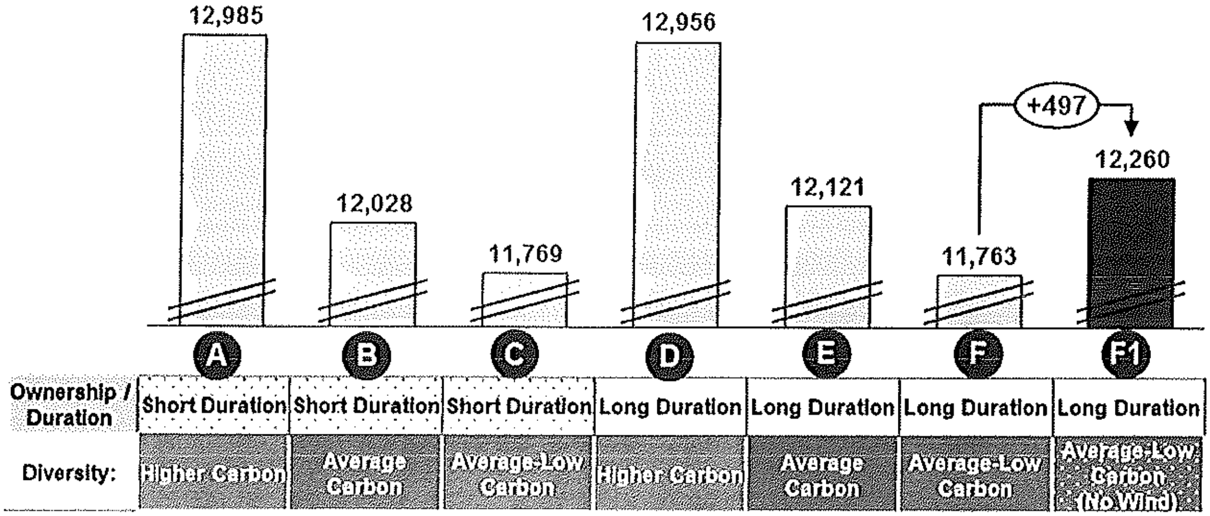


9.3.1 Procuring Wind in 2020

As discussed in Section 4.10.2, tax incentives currently available for renewable energy resources are currently in the midst of a phase out, and projects need to begin construction by a certain date and be in service by a certain date in order to receive the benefits. For wind resources to qualify for 100% of the production tax credit (PTC), projects need to be placed in service by the end of 2020. Solar resources are eligible to receive the investment tax credit (ITC), but do not need to enter into service until the end of 2023 to qualify.

NIPSCO has found that wind resources provide significant value to the portfolio from a cost perspective, and that procuring wind resources in 2020 to realize the full benefits of tax credits is important to achieve the lowest portfolio costs for customers. In order to evaluate the impact of the best-performing All-Source RFP wind resources on the costs of the portfolio, NIPSCO evaluated a variation of Portfolio F that relies solely on solar and solar plus storage resources in place of wind. This portfolio is nearly $500 million more expensive than Portfolio F on a 30-year NPVRR basis, as shown in Figure 9-30. This is due to the fact that the alternative portfolio removes the lowest-cost resources (wind) and replaces them with higher-cost solar resources and a larger amount of higher-cost market purchases.

Figure 9-30: Base Case Replacement Cost NPVRR with No Wind Portfolio



9.3.2 Preferred Plan Summary

From a customer perspective, NIPSCO's preferred plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet future customer needs. NIPSCO also carefully planned and considered the impacts to its employees, the environment, system reliability and impacts on the local economy as the plans were developed. It is important to remember that the integrated resource plan is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

The major components of the NIPSCO supply strategy for the next 20 years are expected to:

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of over 75% of NIPSCO's current coal capacity by the end of 2023 and 100% by 2028
- Continue the Company's commitment to energy efficiency and demand response by executing the current filed DSM plan
- Replace retired coal generation resources with lower cost renewables, including wind, solar and battery storage
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units

- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply;
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services
- Continue to comply with NERC and EPA standards and regulations

9.3.3 Financial Impact

Figure 9-31 shows NIPSCO's financial impact of the preferred plan over the planning period. The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charge, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-31: Financial Impact Summary

Financial Impact Summary	
Operating Costs ($000)	7,357,588
Capital Costs ($000)	4,405,775
Total Revenue Requirement ($000)	11,763,363
Total Energy Requirement (GWh)	203,994
Cents/kWh	5.77

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's. NIPSCO intends to fulfill its commitment in Cause No. 44688, in regard to electric related projects, to "finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Ind. Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39 with at least 60% debt capital.

9.3.4 Capacity Resource Planning With Non Dispatchable Resources

Reliable system planning fundamentally requires having enough resources available to meet customer needs at all times. As discussed in Section 4.8, the NIPSCO plans supply resources to meet its peak demand coincident with MISO system peak demand plus the required reserve margin. NIPSCO recognizes that system planning with renewable resources is more complex than with dispatchable resources and that assumptions based on today's market constructs may ultimately change. NIPSCO believes the plan outlined in the IRP is a 'low regrets' path that provides flexibility to adjust to these potential changes while managing customer cost.

Renewable resource capacity credit assumptions used in the IRP depend on the resource. The 2018 IRP modeling uses resource capacity credit roughly based on current MISO rules and are fixed over the planning horizon. For new MISO Load Resource Zone ("LRZ") 6 wind resources, the IRP modeling uses a fixed 15.6% capacity credit which is based on MISO effective load-carrying capability ("ELCC") from Planning Year 2017. ELCC is a measure of the additional load that the system can supply with an additional generator; it is ultimately a derating factor applied to the nameplate capacity of a resource in order to determine how many megawatts can be counted towards meeting a the local resource adequacy requirements of a load serving entity like NIPSCO.

For new LRZ 6 solar resources, the IRP modeling uses a fixed 50% capacity credit assumption. This assumption is based in part on current MISO methodology which sets annual UCAP based on the 3-year historical output for hours ending 15, 16, and 17 EST. Solar resources without historical data currently receive the 50% class average. NIPSCO uses this placeholder value set by MISO for 1st year operations throughout the entire modeling horizon. NIPSCO understands that MISO intends to move to an ELCC methodology for solar similar to the one used for wind when sufficient data is available.

For new LRZ 6 storage resources, the IRP modeling assumes 4 hour storage required to firm renewables (i.e. 4MWh storage creates 1MW capacity). NIPSCO understands that MISO is currently working through the stakeholder process for storage credit in response to FERC Order 841. Recent work points towards a 5% EFORd assumption and capacity credit based on 4-hour duration.

Although not modeled, renewable capacity credit is likely to change over time. NIPSCO's IRP modeling uses a UCAP assumption and renewable project size is "grossed up" to account for capacity credit. A renewable generator's contribution to meeting peak load is dynamic and depends on multiple factors including:

- Renewable generation profile –when is the unit producing energy?
- Load profile –when do customers demand energy?

- Renewable penetration levels –how much of the system is comprised of renewables?
- ISO-specific policies / methodologies

Capacity credit value and methodology is not fixed and may change. Current capacity credit methodology in MISO matches unit availability with peak load hours during the summer to arrive at a capacity credit.

However, MISO is exploring a Resource Availability and Need ("RAN") methodology that expands resource adequacy from a single summer peak view to look at seasonal needs with greater emphasis on the ability of resources to provide energy all year around. Initial solar capacity credit of 50% will likely change with Effective Load Carrying Capability analysis; both wind and solar capacity credit will change over time with increased renewable penetration levels. MISO has identified a number of available levers to mitigate reductions in resource availability including: resource diversity; geographic diversity; southwest-facing solar; solar tracking; energy storage; demand control and energy efficiency[15].

Notably, the 2018 NIPSCO IRP Preferred Plan portfolio includes many of these mitigation levers, including resource diversity through coal, natural gas, wind, solar and energy storage; geographic diversity with current and planned resources spread across and beyond NIPSCO's electric footprint; demand control; energy efficiency. Furthermore, NIPSCO will consider southwest facing solar and solar tracking in its planned procurement. NIPSCO will continue to monitor how the market evolves and incorporate it into future planning

If capacity credit rules or methodologies change, NIPSCO's IRP path can be cost-effectively scaled to adjust. If additional capacity is required, NIPSCO's modeling, based on RFP data, shows that procuring additional renewable resources is the lowest cost option. As discussed in Section 9.2, the optimization model economically selects a renewable (or renewable + storage) resource over alternatives. By not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change.

Preferred Plan Provides Opportunities to Track Drivers that are Difficult to Quantify Today

Congestion and nodal price risk is one such driver. Energy delivery to the grid is critical to realize benefits from renewables. As part of the selection process for replacement resources identified through the RFP, NIPSCO plans to evaluate system delivery risks (market congestion impacts) associated with each project. For projects shortlisted, NIPSCO will conduct economic planning studies based on transmission congestion and variable fuel cost adjusted for purchase costs and sales revenues using the MISO Transmission Expansion Plan (MTEP) model under the Accelerated Fleet Change planning future.[16] This future assumes 26 GW of coal and natural gas retirements, 22 GW of new wind, and 14 GW of new solar in MISO by 2027. The studies will help

[15] MISO "Renewable Integration Impact Assessment". June 5, 2018. Available at https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

[16] MISO MTEP18 Futures Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results. Available at https://cdn.misoenergy.org/MTEP18%20Futures%20Summary111488.pdf

identify potential system issues with delivering the energy from multiple wind and solar installations throughout Indiana under normal and contingent operating conditions.

Forecasting is not an exact science and NIPSCO recognizes that the current analysis may not capture all potential future states of the world and is committed to tracking market evolutions and will update and incorporate into future IRPs as appropriate. Examples of potential changes include MISO evolution on ancillary services, renewable resource availability/ capacity credit forecasts, seasonal constructs, etc.

As discussed in Section 9.4, NIPSCO's short-term action plan does not commit to immediately filling the entire 2023 capacity gap but leaves room to evaluate market and technology changes on a dynamic basis.

9.4 Short-Term Action Plan

NIPSCO's short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the Schahfer 14,15,17,18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire the Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.

NIPSCO will select replacement resources identified through the 2018 All-Source RFP evaluation process, prioritizing resources with expiring federal tax incentives to achieve lowest customer cost. For the projects selected, NIPSCO will pursue the required approvals from the commission to acquire those projects. To fill any short term capacity needs during this period, NIPSCO will rely on MISO market purchases or short term PPA(s). NIPSCO will also continue to implement the filed DSM plan for 2019 to 2021

Lastly, NIPSCO will conduct a subsequent All-Source RFP solicitation to identify preferred resources to fill the remainder of the 2023 capacity need. Figure 9-32 summarizes the short term actions for the 2018 NIPSCO IRP.

Figure 9-32: Short-Term Action Plan Summary

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations
Identify and implement required reliability and transmission upgrades resulting from retirement of the units
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term PPA
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
Continue implementation of filed DSM Plan for 2019 to 2021
Comply with NERC, EPA and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

9.4.1 Procurement of Preferred Resources

NIPSCO recognizes that the amount of projects that need to be acquired to support its preferred replacement plan will require much time, effort and planning. NIPSCO will utilize a multi-phase approach for acquiring those resources. As discussed in the Short Term Action Plan, in the early phases, NIPSCO will look to primarily acquire tax advantaged wind projects, with solar and solar plus storage targeted for later phases. NIPSCO will use the early phases to build the organization capabilities, repeatable processes and procedures to support later procurement phases for the need identified. NIPSCO will also seek to engage with counterparties from the 2018 all source RFP that have extensive demonstrated development, construction and operational experience with wind, solar and storage projects. Lastly, NIPSCO will look to find process efficiencies by standardizing terms and conditions in agreements with counterparties and standardizing construction oversight procedures across all projects.

9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This IRP quantifies changes associated with the emerging energy market place to best accommodate risks associated with customer cost and service. No longer is it possible to view the world in terms of choosing a simple least cost option; it is now necessary to think it terms of minimizing future environmental impacts and maximizing resource diversification all the while ensuring affordable service to customers.

The IRP process and document are ever evolving and no filed document is ever up-to-date with the world as it stands the day after filing. Rather than trying to model our future world with exact precision, this IRP seeks to utilize a broad set of scenarios assumptions in combination with advanced risk treatment using stochastics to understand and develop resource plans and portfolios that perform best under multiple potential futures.

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

NIPSCO is focused on enhancing how it serves and interacts with its customers. Whether upgrading the energy infrastructure to make sure it's prepared to meet future needs, providing more convenient options to connect with the Company in-person, online or via telephone or expanding energy efficiency programs, customers are the central focus.

10.1.1 Leveraging Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the IURC's Consumer Affairs Division. The Company also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the industry. This data is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and added programs and other offerings that have been instituted in recent years.

For example, recent J.D. Power Electric Customer Satisfaction survey results have highlighted the need to expand how NIPSCO communicates with customers during power outages. As a result, the Company launched NIPSCO Alerts, which enables customers to receive updates regarding power outages, including estimated restoration time via text, email, or telephone. As part of this, NIPSCO also added the option for customers to text to report a power outage. With this new offering, NIPSCO customers can now choose the option that is most convenient for them – telephone, online (desktop and mobile) and text. These enhancements were part of why NIPSCO was recently awarded with Chartwell's top award for 2018 Outage Communications Best Practices among all utilities nationally.

10.1.2 NIPSCO's Customer Workshop Series

NIPSCO recently kicked off the 7th season of its Customer Workshop Series in partnership with Purdue University. Since 2011, hundreds of NIPSCO Transmission and C&I customers from all over northern Indiana have attended the various workshops. With topics ranging from technical (Understanding HVAC, Fundamentals of Compressed Air, Energy Savings 101, etc.) to interpersonal (Six Sigma, Managing Time & Stress, Becoming a Leader, etc.), customers are able to pick which workshops are valuable to their business and reserve openings for themselves and/or their colleagues.

Attendees are able to interact with industry experts, representatives from the NIPSCO Major Account team, as well as their peers at other companies, learning best practices and voicing their current challenges and solutions in an open, classroom setting. Each season, customers are surveyed and feedback is used to improve the subsequent season. Changes for the 2018 season included additional workshops in the South Bend area, as well as a class geared towards navigating generational changes in the workplace.

10.1.3 New Business Department

The New Business Department was formed in July of 2015 to add value for customers and stakeholders by providing a focus on new business activities for all customers (residential, and C&I). The goals include:

- Continuous improvement of the new business process "from first call to install"
- Single source accountability for policy maintenance
- Enhancing relationships with builder/developer community
- Improving metrics to inform on efficiency and effectiveness
- Supporting capital budget methodology to increase clarity
- Managing growth programs including Electric Vehicle, Feed-In Tariff, Green Power, Compressed Natural Gas

The New Business Department has responsibility for any customer that requests new service, upgrade of service, retirement of service, or relocation of service. NIPSCO's new business representatives are specifically trained in the details of these transactions and provide a resource for customer issues. Since its inception, the New Business Department has undertaken initiatives to:

- Create a single Site Readiness policy for NIPSCO
- Provide automated emails to customers with project status updates
- Revise key performance indicators to better inform on execution levels
- Simplify agreements for all customer classes
- Establish new accounting codes to provide clarity into new service costs

The New Business Department expanded in 2016 and now includes external, customer facing representatives and internal support to assist customers with their new service connections. The New Business Department continues its efforts to evaluate the new business process to determine opportunities for increased efficiency and improved customer service. An end-to-end process map has been completed, which has helped to identify additional areas of opportunity.

10.1.4 Customer Feedback

Customer feedback is essential in NIPSCO's development of customer support and service offerings to provide for an exceptional customer experience. NIPSCO utilizes an on-line group of customers to provide feedback on project offerings and channel options. NIPSCO utilized this on-line group, along with an additional in-person focus group, in the redesign of its customer bill that launched in the spring of 2016. NIPSCO also surveys customers to determine customer satisfaction with the call center and interactions with field personnel, as well as with on-line experiences such as mobile, integrated voice response and web. Customer surveys are also used to capture specific customer issues and to gain immediate feedback on the quality of NIPSCO's customer service. NIPSCO uses the results of these surveys, as well as the information obtained through the J.D. Power Customer Satisfaction Surveys, to identify potential ways to improve the overall customer experience including training and development for customer service representatives and field personnel.

In addition to the J.D. Power Customer Satisfaction Surveys, NIPSCO also relies on customer feedback obtained through MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the Commission's Consumer Affairs Division to discover service improvement opportunities. NIPSCO also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the utility industry. Customer feedback is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and additional programs and other offerings that have been instituted in recent years.

10.1.5 Community Partnerships - Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels ("CAPs"), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has five regions across the Company's footprint for the CAPs. CAPs are comprised of individual customers as well as local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues. This year, as part of the development of the IRP, the CAPs were asked to design a portfolio to meet NIPSCO's electricity needs. The activity led to a great deal of discussion around the best portfolio and provided insight for NIPSCO and CAP members.

10.2 Customer Programs

10.2.1 Feed-in Tariff – Rate 765

NIPSCO's Renewable Feed-in Tariff ("FIT") Phase I was approved on July 13, 2011 in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a rate greater to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a Renewable Power Purchase Agreement ("RPPA"). Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An Interconnection Agreement ("IA") and RPPA are required to reserve capacity or enter the queue.
- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.
- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March of 2015 with a total subscription of 29.7 MW and is summarized in the Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015 in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March of 2015 and Phase II, Allocation II in March of 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2 shows the subscription for Phase II as of July, 2018.

Table 10-2: FIT Phase II Project Totals

Technology	In-service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	110	74	184
Intermediate Solar	3,576	4,380	7,956
Micro Wind	20	0	20
Intermediate Wind	0	1,000	1,000
Biomass	0	0	0
Total	3,706	5,454	9,160

With over 37 MW currently interconnected in the FIT program, as of December 31, 2017, NIPSCO has a total metered generation from customers selling electricity of 473,379,090 kWh.

Table 10-3 shows the annual production and growth by technology segment.

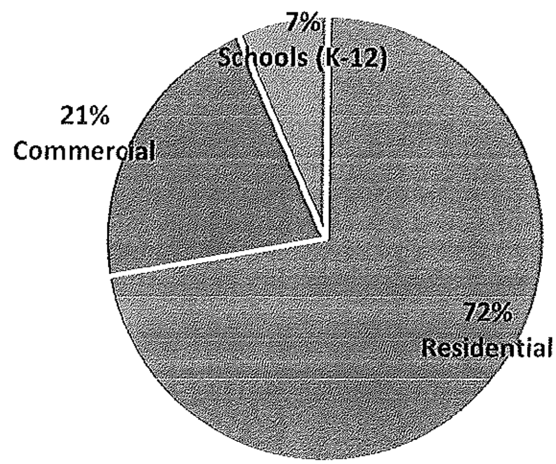
Table 10-3: Annual Production by Technology – Generation (kWh)

Technology	2011	2012	2013	2014	2015	2016	2017	*Total*
Biomass	6,219,791	19,152,432	31,602,728	49,916,700	81,369,723	83,552,339	89,486,440	361,300,153
Large Solar	-	433,758	15,789,457	21,665,115	22,436,103	22,696,839	24,391,349	107,412,621
Small Solar	-	118,895	471,806	718,758	818,332	825,066	848,789	3,801,646
Large Wind	-	-	90,113	165,880	217,949	165,593	167,807	807,342
Small Wind	-	3,588	15,721	12,051	9,462	8,019	8,487	57,328
Total	6,219,791	19,708,673	47,969,825	72,478,504	104,851,569	107,247,856	114,902,872	473,379,090

10.2.2 Net Metering – Rider 780

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operating a solar, wind, biomass or hydro generating facility that has a nameplate capacity less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and Interconnection Agreement receive a credit for each kWh provided to NIPSCO above their own usage requirement. NIPSCO's Net Metering program capacity cap is limited to 45 MW and total subscription is as of December 31, 2017 was 10.69 MW. The total measured generation by the Net Metering customers for 2017 was 3,667,721 kWh. The current classification of NIPSCO's 270 Net Metering customers is shown in Figure 10-1.

Figure 10-1: Classification of Net Metering Customers



10.2.3 Electric Vehicle Programs (Phase I and Phase II) – Rider 785

10.2.3.1 NIPSCO IN-Charge Electric Vehicle Program – At Home (Phase I)

NIPSCO's IN-Charge Electric Vehicle ("EV") Pilot Program was approved on February 1, 2012 in Cause No. 44016 through January 31, 2016. NIPSCO launched its IN-Charge Electric Vehicle Program - At Home on April 2, 2012. On October 29, 2014, the Commission approved NIPSCO's 30-day filing to extend its EV Program an additional two years through January 31, 2017. Under the extended EV Program, the incentive of up to $1,650 per customer continued for a period through January 31, 2017 or until such time as the funds were depleted, which occurred earlier. As of June 30, 2016, 250 customers had received program incentives, exhausting the funds available for customer incentives. On January 11, 2017, in Cause No 44828, the Commission approved NIPSCO's request for a modification of its EV Program to provide that participants of record as of January 31, 2017 would be subject to an energy charge of $070894 per kilowatt hour for all kilowatt hours used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months. This program expires on December 31, 2018.

As of January 31, 2018, NIPSCO had received 382 customer enrollment requests. Estimates for installation costs, including the cost of a home EV charger, ranged from $667 to $6,325 with an average of $2,062. The average incentive amount used by customers with completed installations was $1,629.

The Bureau of Motor Vehicle registrations that show registrations in counties that NIPSCO has electric service in are as follows:

Table 10-4: NIPSCO's Electric Vehicle Customer Request Breakdown

Row Labels	2014	2015	2016	2017
BENTON	1	1	1	3
DEKALB	1	4	18	18
ELKHART	33	45	63	78
FULTON	4	5	5	4
JASPER	4	7	11	18
KOSCIUSKO	12	17	22	32
LAKE	116	154	185	250
LAPORTE	17	30	40	62
MARSHALL	7	8	9	14
NEWTON	2	2	2	7
PORTER	68	84	107	140
PULASKI		1	2	4
SAINT JOSEPH	50	71	87	148
STARKE	1	3	3	5
STEUBEN	3	6	10	18
WHITE	2	5	5	7
Grand Total	**321**	**443**	**570**	**808**

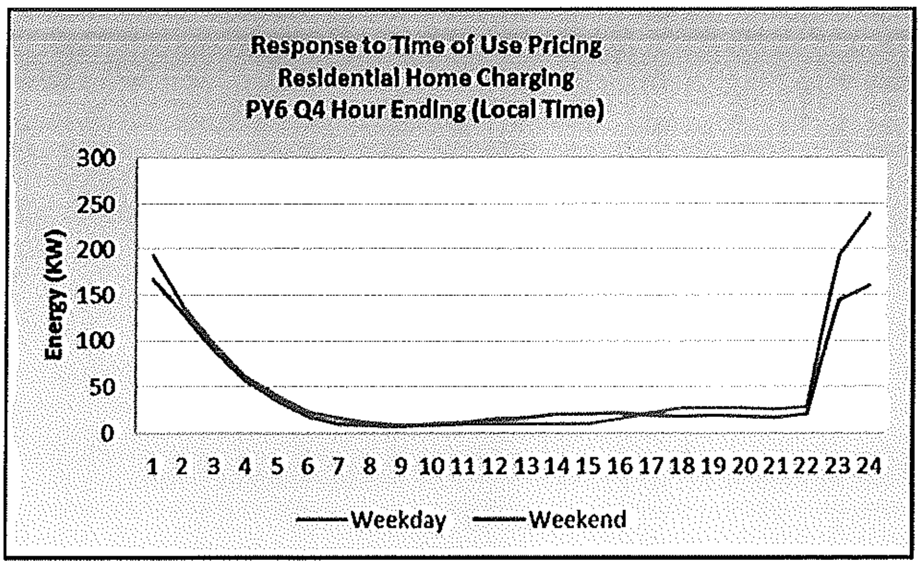
On average, EV customers that were a part of NIPSCO's pilot program used approximately 220 kWh per month to charge their electric vehicle. The actual amount of consumption will vary by individual customer. Customer vehicle type will impact the consumption significantly as well as the demand on the grid. A Tesla Model S charging demand is 10 kW, while a Chevrolet Volt charging demand is only 3.3 kW. The Nissan Leaf charging demand ranges from 3.3 kW to 6.6 kW depending on the options installed in the car. To put demand in perspective, an average size residential home has approximately 33 kW in connected load of which, on average, 18 kW might be on during coincidental peak time. For comparison, typical residential demand breakdown by appliance is listed below:

- Water Heater – 4.5 kW
- Range / Oven – 8.0 kW
- Central Air Conditioner – 6.0 kW
- Clothes Dryer – 5.0 kW
- Dishwasher – 2.0 kW
- Lighting, Fans, Appliances, Other – 7.5 kW

NIPSCO's Rate Case Order indicates that its typical residential electric customer used 698 kWh per month on average during the weather normalized test year. The average EV consumption during the pilot period was approximately 220 kWh or approximately 31 percent of the average home consumption. The type of vehicle purchased and the number of miles driven by the customer will directly impact the average consumption of the vehicle for each individual customer.

NIPSCO found that the "free" energy and discounted energy during the off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior during the pilot. The typical usage by hour over the recent three month period analyzed (November 2017 through January 2018) is shown in Figure 10-2. The vast majority of the time, EV residential customers began their charging session at 10 p.m. when the energy discounted period began and their vehicles were fully charged by 6 a.m. when the energy discounted period ended. As predicted, the total energy consumption was higher during the work week, when owners typically drove their vehicles more than they did on weekends. The analysis indicates that time of use rates do have an impact on pushing 80% of EV loads to more preferred off-peak time for utilities.

Figure 10-2: Response to Time of Use Pricing



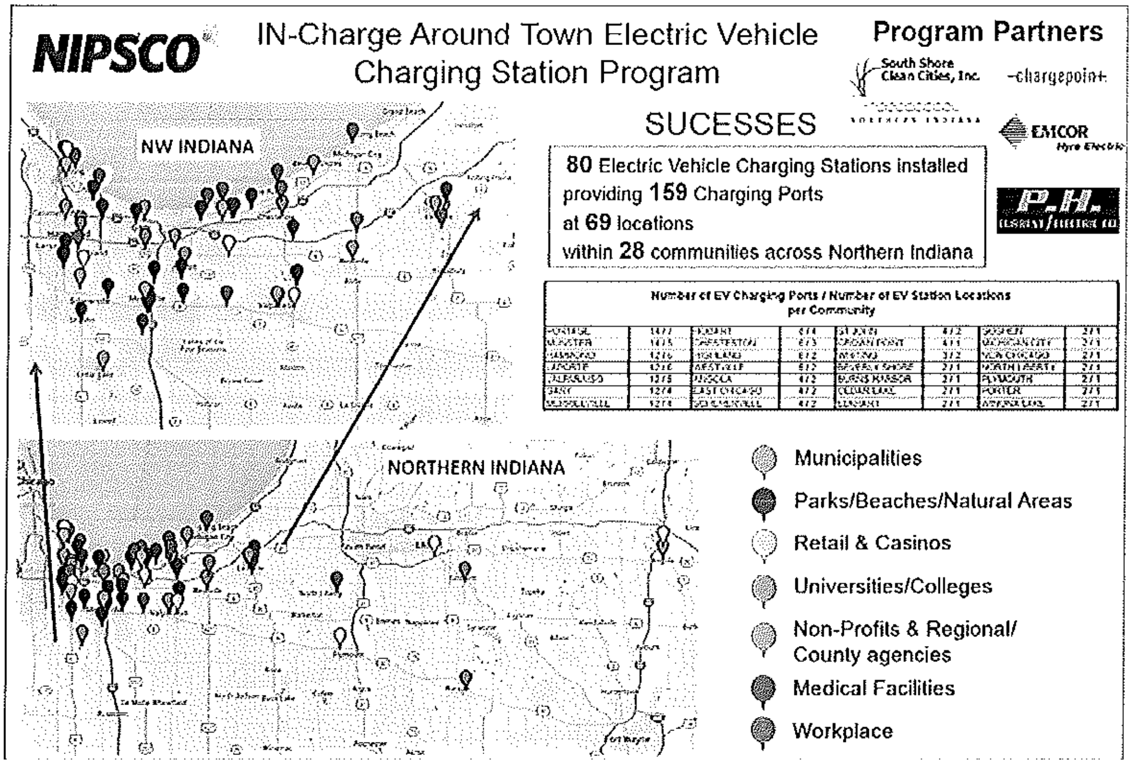
10.2.4 NIPSCO IN-Charge EV Program – Around Town (Phase II)

NIPSCO partnered with South Shore Clean Cities to expand opportunities for alternative fuel, through the launch of a public charging station incentive program in February 2014. The NIPSCO IN-Charge EV Program – Around Town made it easier and more affordable for businesses and organizations to install public charging infrastructure. The In-Charge – Around Town program was available to commercial / industrial electric customers across northern Indiana and was offered until program funds were exhausted in June 2016.

For every unit of electricity used by IN-Charge Around Town charging stations during the program, NIPSCO bought an equivalent amount of renewable energy certificates ("RECs") – the environmental attributes associated with electricity that is generated from renewable sources, such as wind power.

As of June 30, 2016, NIPSCO had installed 80 public charging stations providing 159 charging ports at 69 locations. Figure 10-3 shows a map of the station locations and application status:

Figure 10-3: Station Locations and Application Status



10.2.5 Green Power Program – Rate 760

NIPSCO's Green Power Rider ("GPR") program was approved on December 19, 2012 in Cause No. 44198 through December 31, 2014. NIPSCO's request for extension of its GPR Program, with certain modifications, and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014 in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage to be attributable to power generated by renewable energy sources. Customers can enroll online or by calling NIPSCO. .

Green Power is energy generated from renewable and/or environmentally-friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of Green Power include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green Power includes the purchase of RECs from the sources described above. For the GPR Program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage to be attributable to Green Power. In addition to those options, NIPSCO's C&I customers also have the option to designate 5% or 10% of their total electricity usage to be attributable to Green Power. As of December 31, 2017, 1,191 customers were participating in the GPR Program. Figure 10-4 shows the breakdown among residential customers as of December 31, 2017.

Figure 10-4: Residential Customer Count

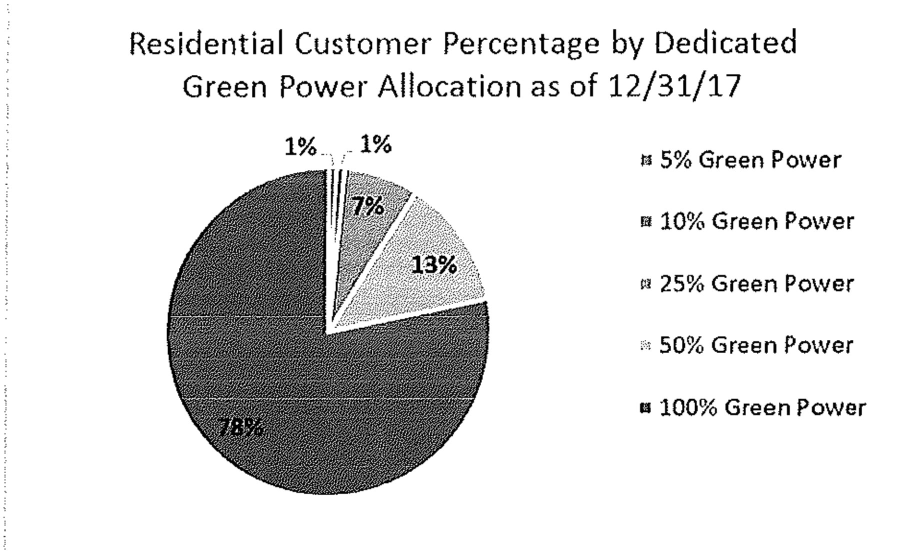
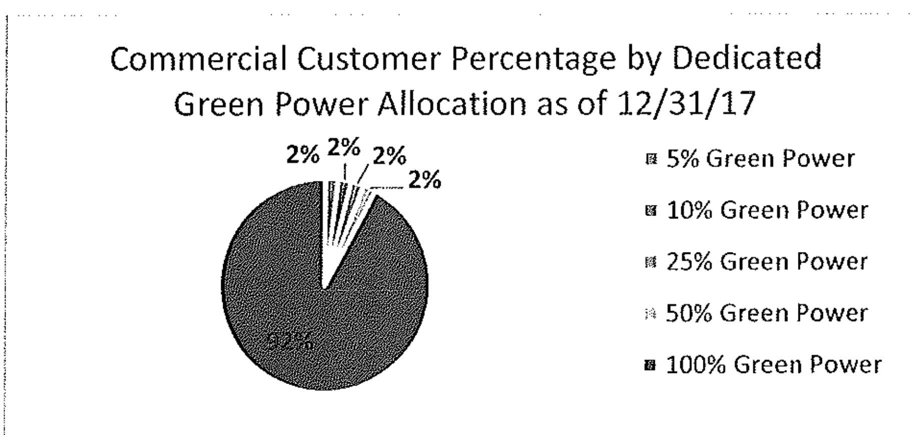


Figure 10-5 shows the breakdown of commercial and industrial customers as of December 31, 2017.

Figure 10-5: Commercial Customer Count



NIPSCO's GPR Program for the period of January 1 through December 31, 2017 accounted for 18,274,702 kWh energy consumption designated as Green Power. Residential customers accounted for 6,973,682 kWh of energy consumption and commercial and industrial customers accounted for 11,301,020 kWh of energy consumption of designated Green Power. For both residential and commercial customers, the majority of the GPR Program enrollments designate 100% of their energy as Green Power. Table 10-5 shows the energy consumption designated as Green Power for participating customers by rate for the period January 1 through December 31, 2017.

Table 10-5: 2017 Green Power Customers by Rate (kWh)

Rate	Participation %	17-Jan	17-Feb	17-Mar	17-Apr	17-May	17-Jun	17-Jul	17-Aug	17-Sep	17-Oct	17-Nov	17-Dec	TOTAL
760	100%	986	856	796	808	644	669	639	620	770	771	904	722	9,185
711	5%	455	364	294	256	219	305	387	390	320	293	241	267	3791
	10%	833	689	594	581	616	886	986	941	745	665	625	600	8,761
	25%	13,075	12,096	11,807	10,064	9,510	14,579	17,815	17,464	14,349	12,998	10,762	11,936	156,455
	50%	48,352	39,945	37,771	37,629	33,844	51,781	62,997	61,220	49,347	44,746	38,478	41,564	547,674
	100%	574,872	483,575	431,576	427,760	372,190	540,691	677,110	673,250	570,611	519,354	465,081	520,931	6,257,001
721	5%	-	-	-	-	-	173	183	174	143	149	115	109	1,046
	10%	1,959	1,515	1,651	1,667	1,681	1,968	1,720	1,888	1,696	1,728	1,496	1,408	20,377
	25%	182	126	169	213	146	223	264	275	177	116	88	96	2,075
	50%	718	569	629	639	961	1,013	1,413	1,451	960	602	382	470	9,807
	100%	91,908	80,847	73,865	65,371	59,997	58,862	65,804	72,766	72,342	72,219	70,681	78,300	862,962
723	5%	3,360	-	-	-	-	-	-	-	-	-	-	-	3,360
	100%	50,800	54,040	52,280	40,640	47,320	46,000	42,280	49,520	49,280	43,960	48,600	44,640	569,360
724	100%	363,168	408,176	465,600	450,080	471,808	530,784	523,024	532,336	412,832	445,424	394,208	388,000	5,385,440
726	100%	337,152	341,632	354,160	356,064	397,232	453,792	421,904	418,400	398,128	370,656	299,568	288,720	4,437,408
TOTAL		1,487,820	1,424,430	1,431,192	1,391,772	1,396,168	1,701,726	1,816,526	1,830,695	1,571,700	1,513,681	1,331,229	1,377,763	18,274,702

Participating customers are billed under their current applicable rate, with a separate line item showing the premium to participate in the GPR Program. This premium is calculated by multiplying the GPR Rate by the kWhs the customer specifies to be subject to the GPR. Table 10-6 shows the Green Power premiums applicable during the period January 1, 2017 through December 31, 2018.

Table 10-6: Green Power Premiums

January 2017 through December 2017	January 2018 through June 2018	July 2018 through June 2019
$0.001640	$0.002940	$0.001805

10.3 Corporate Development and Community Support

10.3.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO's service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1.1 million in economic development efforts each year, which has resulted in 67 new businesses or expansions and 7,500 local jobs in the last 10 years.

NIPSCO's Rider 777 – Economic Development Rider ("EDR") offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside its service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

Even with the continued growth, NIPSCO's transmission and distribution system is designed to provide all customers with reliable energy services, and NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory. Additionally, the investments NIPSCO is making to modernize and upgrade its energy infrastructure continue to have a positive, direct impact on local businesses.

10.3.2 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps innovate ideas and processes, gain a competitive advantage and benefit NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers that are typically underutilized in the supply chain of a large corporation.

In 2017, NIPSCO's direct supplier spend in Indiana was $155 million, and the direct supplier spend with diverse Indiana businesses was $40 million.

10.3.3 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some of the highlights include:

- **Ivy Tech Partnership for Energy Industry Training Program:** Program began in 2009 and provides training in electric-line, power plant technology and gas technology areas. NIPSCO has hired more than 50 students from the program and graduates are guaranteed an interview opportunity. Additionally, NIPSCO provides instructors for these training classes and recently provided a full-scale electric distribution system for training purposes built within the Ivy Tech Valparaiso campus energy technology lab – the only such facility in an educational setting in Indiana.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School and Westville High School. Participants have entered the Ivy Tech program and are in the Apprentice Program at the International Brotherhood of Electrical Workers (IBEW), with more than 100 students that have gone through the program.

- **IN-Power Youth Mentoring Program:** IN 2010, NIPSCO introduced the IN-POWER Youth Mentoring Program – a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-

POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety, while teaching them about the various aspects of science, technology, engineering and math needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy (AABE) Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships among other opportunities.

- **Junior Achievement Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. For the last several years, NIPSCO has supported a "JA Day" in a local Hammond school.

- **City of Gary Summer of Opportunity Job Program:** The Summer of Opportunity places youth in meaningful work opportunities throughout the City of Gary, with Lunch & Learn workshops featuring local professionals with every other session focusing on financial literacy. Local youth staff six summer program sites that offer summer meals and learning. Mayor Karen Freeman-Wilson, NIPSCO, Gary Youth Services Bureau, Urban League of NWI and the Gary Chamber of Commerce have partnered to create a set of supports that enable strong transitions from school year to school year and from high school to college and career.

- **Girl Scouts Engineering Day:** For more than 5 years, NIPSCO has hosted more than 125 girls from kindergarten to fourth grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops along with some young relatives of NIPSCO and NiSource employees. The four hour event is part of the company's efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in Stem related careers. The event was organized by the employee resource group Developing and Advancing Women at NiSource (DAWN).

10.3.4 Corporate Citizenship

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO and its employees donate time, money, and other resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Basic Human Needs
- Education
- Public Safety & Emergency Response
- Environmental Stewardship

- Economic Development

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come. In 2017, NIPSCO and the NiSource Charitable Foundation contributed more than $1.78 million to local organizations throughout its service territory.

A highlight of those effort is NIPSCO's annual Charity of Choice campaign, where employees select one nonprofit organization or an area of need to support. Fundraisers, volunteerism and other activities are planned throughout a summer-long, employee-led campaign. Recent benefactors and causes selected by employees have included autism, veterans, Boys and Girls Clubs, the American Heart Association, the American Red Cross and more.

10.3.5 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called "Dollars for Doers," cultivated by NiSource, employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2017, NIPSCO employees contributed 5,535 volunteer hours, equating to $110,700 donated to charities of their choice. Additionally, NIPSCO employees volunteer their personal time and resources with more than 100 local nonprofit boards, associations and other local community efforts each year.

List of Appendices

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Confidential Appendix D	Hourly Load Shapes and Duration Curve, Seasonal Load Shapes, Scenarios and Sensitivities, Scenario Planning Variable Breadth and Diversity, Sensitivity Modeling Results, NIPSCO Unit Retirement Analysis, Scenarios and Sensitivity Results
Confidential Appendix E	Sargent & Lundy Engineering Study Technical Assessment
Confidential Appendix F	NIPSCO FERC Form 715

Section 11. Compliance with Proposed Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email and hand delivery on October 31, 2018
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1, Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	
An IRP must include the following:	

Rule	Section(s)
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.8 Section 3.8 Section 3.9 Section 3.10 Section 3.11
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.11 Section 3.12
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5.1 Section 5.4
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.9 Confidential Appendix F
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Confidential Appendix B
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 8.3 Section 8.4 Section 8.5 Section 9.2 Section 9.3Appendix F
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 9.2 Section 9.3
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.1 Section 9.4
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Section 2 Section 3.2 Section 4.4 Section 4.9

Rule	Section(s)
	Section 5.1 Section 5.2 Section 5.5 Section 5.6 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2 Section 9.3Appendices A through D and Confidential Appendices J
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3.2.1 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3.2
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2

Rule	Section(s)
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3.2 Section 5.2
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 9 Section 6.2 Section 10.2.1 Section 10.2.2
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A Appendix C
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.4
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.2.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 9.3 Section .2.3
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high	Section 9.3

Rule	Section(s)
probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 9.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix F
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Section 2.2 Section 3.2 Section 8.1 Section 8.3 Section 8.4 Section 9.3 Appendix B Appendix C

Rule	Section(s)
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.2 Appendix B
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Appendix C
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.9 Section 5 Appendix B Confidential Appendix E
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Section 3 Appendix C,
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3.3 Section 3.4 Section 3.5

Rule	Section(s)
	Section 3.6 Section 3.7 Section 3.11
(3) Actual and weather normalized energy and demand levels.	Section 3.11
(4) A discussion of methods and processes used to weather normalize.	Section 3.10
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.11 Section 3.12
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.13
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.12
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information:	Section **Error! Reference source not found.** Section 4.5

Rule	Section(s)
(1) The net dependable generating capacity of the system and each generating unit.	
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.9 Section 4.10 Section 9.1
(3) A fuel price forecast by generating unit.	Section 8.1.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.4.1 Section 4.4.2 Section 4.4.3
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.4 Section 6.1.6 Section 6.1.7 Section 6.1.8
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Section 3.2 Section 5.1 Section 5.6 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.2
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs. For a demand-side resource identified in the IRP, the utility shall, include the following:	Section 5.2 Section 5.5 Appendix B

Rule	Section(s)
(A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 4.4 Section 4.5 Section 4.9
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1.7 Section 6.1.8 Section 6.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1.7 Section 6.1.8 Section 6.2
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.7 Section 6.1.8

Rule	Section(s)
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1.3
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1.3
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.9 Section 5.3 Section 5.4
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge. (2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Confidential Appendix E
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test. (5) Other reasonable tests accepted by the commission.	Section 5.5 Appendix B
(d) A utility is not required to calculate a test result in a specific format.	N/A

Rule	Section(s)
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.5 Appendix B
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Appendix B
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 8.3
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Appendix D
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 9.3
(2) Identification of the variables used.	Section 9.3

Rule	Section(s)
(3) Identification of the standards of reliability.	Section 9.3
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2.3
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 9.3
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3 Appendix B
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3.3 Confidential Appendix E
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance;	Section 9.3

Rule	Section(s)
(vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 9.3
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2.2
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio.	Section 1.1 Section 9.4

Rule	Section(s)
(B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq.* and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various technical resource manuals ("TRMs"), including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.

Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO is currently conducting a MPS that will include primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO is considering using customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.

Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.