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Hoosier Energy REC, Inc.
2016 Update to
2014 Integrated Resource Plan
Public Version

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1 Introduction

This update to the *2014 Integrated Resource Plan* (the Plan or the IRP) is submitted by Hoosier Energy Rural Electric Cooperative Indiana 106 Statewide ("Hoosier Energy") pursuant to the requirements of Rule 170 of the Indiana Administrative Code 4-7 (hereinafter referred to as the Rule).

The IRP update contains five subsections. The first section (Section 1.0) provides an introduction to the 2014 IRP update. The second subsection (Section 2.0) summarizes the energy and demand forecasts and the changes to those forecasts from the 2014 IRP filing. The third subsection (Section 3.0) describes changes to the resource portfolio subsequent to the 2014 IRP filing. The fourth subsection (Section 4.0) provides an assessment of resource options as modeled by GDS Associates. Section 5.0 contains the Short-Term Action Plan.

2 Energy and Demand Forecast Comparisons

This section presents a comparison of Hoosier Energy's current energy and demand forecasts to those that were presented in the 2014 IRP. The forecasts used in the update were taken from Hoosier Energy's 2015 Power Requirements Study, which meets all requirements as established in the Hoosier Energy Power Requirements Study Work Plan and the Rural Utilities Service Rule 1710, sub-part E, sections 1710.200 through 1710.210. The PRS fully documents the forecast of electric energy sales and peak demand for Hoosier Energy. The development of the PRS is a joint effort between the staff at Hoosier Energy and its member systems, with contributions and review from RUS.

Hoosier Energy compared forecasted Peak Demand and Energy Requirements for the Base Case, as well as High Load and Low Load scenarios. As presented in the following pages, the Base Case scenario showed an average increase in Peak Demand of 1.3 percent for the period 2017 – 2034, while the average Energy Requirement increased by 0.6 percent.

In the High Load Scenario, the Base Case scenario showed an average increase in Peak Demand of 0.2 percent for the period 2017 – 2034, while the average Energy Requirement decreased by 0.3 percent.

In the Low Load Scenario, the Base Case scenario showed an average increase in Peak Demand of 1.6 percent for the period 2017 – 2034, while the average Energy Requirement increased by 0.9 percent.

Hoosier Energy Rural Electric Cooperative, Inc.
Comparison of Forecasted Demand and Energy Requirements - Base Case
For Calendar Years 2017 - 2036

	Peak Demand - MW			Energy Requirements - MWh		
Year	2014 IRP	2016 IRP Update	Annual Percentage Change	2014 IRP	2016 IRP Update	Annual Percentage Change
2017	1,502	1,539	2.5%	7,756,121	7,974,543	2.8%
2018	1,530	1,550	1.3%	7,821,145	8,038,473	2.8%
2019	1,557	1,563	0.4%	8,086,585	8,104,815	0.2%
2020	1,571	1,576	0.3%	8,160,125	8,179,218	0.2%
2021	1,584	1,594	0.6%	8,233,293	8,304,766	0.9%
2022	1,597	1,619	1.4%	8,310,212	8,372,562	0.8%
2023	1,606	1,631	1.6%	8,364,215	8,437,835	0.9%
2024	1,617	1,646	1.8%	8,427,489	8,513,875	1.0%
2025	1,629	1,659	1.8%	8,498,231	8,579,136	1.0%
2026	1,642	1,673	1.9%	8,572,987	8,642,545	0.8%
2027	1,657	1,687	1.8%	8,656,481	8,709,603	0.6%
2028	1,673	1,701	1.7%	8,740,881	8,781,046	0.5%
2029	1,683	1,708	1.5%	8,792,237	8,813,647	0.2%
2030	1,700	1,722	1.3%	8,885,843	8,882,908	0.0%
2031	1,719	1,738	1.1%	8,985,433	8,956,824	-0.3%
2032	1,738	1,753	0.9%	9,086,958	9,032,243	-0.6%
2033	1,755	1,768	0.7%	9,177,828	9,103,303	-0.8%
2034	1,773	1,783	0.6%	9,269,606	9,178,738	-1.0%
2035		1,798			9,252,168	
2036		1,814			9,326,185	
Average Percentage Change			**1.3%**			**0.6%**

Table 1: Comparison of Forecasted Demand and Energy Requirements – Base Case

Hoosier Energy Rural Electric Cooperative, Inc.
Comparison of Forecasted Demand and Energy Requirements - High Load Case
For Calendar Years 2017 - 2036

	Peak Demand - MW			Energy Requirements - MWh		
Year	2014 IRP	2016 IRP Update	Annual Percentage Change	2014 IRP	2016 IRP Update	Annual Percentage Change
2017	1,610	1,588	-1.4%	8,283,840	8,236,241	-0.6%
2018	1,627	1,610	-1.0%	8,403,752	8,356,523	-0.6%
2019	1,648	1,635	-0.8%	8,541,284	8,481,563	-0.7%
2020	1,671	1,658	-0.8%	8,671,990	8,616,661	-0.6%
2021	1,696	1,699	0.2%	8,803,755	8,804,547	0.0%
2022	1,720	1,726	0.3%	8,940,875	8,936,345	-0.1%
2023	1,741	1,752	0.6%	9,056,214	9,067,310	0.1%
2024	1,764	1,780	0.9%	9,182,795	9,210,744	0.3%
2025	1,789	1,806	1.0%	9,318,630	9,345,023	0.3%
2026	1,816	1,833	0.9%	9,460,354	9,479,005	0.2%
2027	1,845	1,862	0.9%	9,612,613	9,618,201	0.1%
2028	1,874	1,891	0.9%	9,767,494	9,763,679	0.0%
2029	1,898	1,912	0.7%	9,891,777	9,871,959	-0.2%
2030	1,930	1,941	0.6%	10,060,523	10,018,660	-0.4%
2031	1,965	1,972	0.4%	10,237,827	10,172,532	-0.6%
2032	2,000	2,004	0.2%	10,419,279	10,329,719	-0.9%
2033	2,036	2,035	0.0%	10,606,826	10,484,073	-1.2%
2034	2,073	2,067	-0.3%	10,797,749	10,645,110	-1.4%
2035		2,098			10,804,787	
2036		2,129			10,966,858	
Average Percentage Change			**0.2%**			**-0.3%**

Table 2: Comparison of Forecasted Demand and Energy Requirements – High Load Case

Hoosier Energy Rural Electric Cooperative, Inc.
Comparison of Forecasted Demand and Energy Requirements - Low Load Case
For Calendar Years 2017 - 2036

	Peak Demand - MW			Energy Requirements - MWh		
Year	2014 IRP	2016 IRP Update	Annual Percentage Change	2014 IRP	2016 IRP Update	Annual Percentage Change
2017	1,443	1,452	0.6%	7,403,581	7,497,056	1.3%
2018	1,439	1,452	0.9%	7,420,388	7,508,939	1.2%
2019	1,441	1,455	1.0%	7,452,758	7,521,752	0.9%
2020	1,445	1,458	0.9%	7,475,727	7,541,485	0.9%
2021	1,448	1,476	1.9%	7,497,635	7,611,599	1.5%
2022	1,450	1,480	2.1%	7,522,444	7,623,185	1.3%
2023	1,449	1,482	2.3%	7,523,962	7,631,481	1.4%
2024	1,449	1,485	2.5%	7,233,612	7,649,784	5.8%
2025	1,451	1,487	2.5%	7,549,821	7,656,669	1.4%
2026	1,453	1,488	2.4%	7,569,039	7,661,121	1.2%
2027	1,457	1,491	2.3%	7,596,105	7,668,665	1.0%
2028	1,461	1,493	2.2%	7,623,305	7,679,760	0.7%
2029	1,459	1,488	2.0%	7,616,033	7,651,441	0.5%
2030	1,465	1,490	1.7%	7,649,867	7,659,151	0.1%
2031	1,471	1,493	1.5%	7,688,220	7,670,244	-0.2%
2032	1,478	1,496	1.2%	7,727,392	7,682,187	-0.6%
2033	1,484	1,498	0.9%	7,766,029	7,689,401	-1.0%
2034	1,490	1,501	0.7%	7,804,859	7,699,984	-1.3%
2035		1,503			7,711,534	
2036		1,506			7,723,101	
Average Percentage Change			**1.6%**			**0.9%**

Table 3: Comparison of Forecasted Demand and Energy Requirements – Low Load Case

Consumer Class Breakdown[1]

The consumer mix on the Indiana portion of the Hoosier Energy system changed slightly over the 2003 - 2013 period. In 2003, 95.0% of the system's consumers were residential, while in 2013, 94.3% were residential. The number of residential consumers increased from 226,749 in 2003 to 279,339 in 2013. By the year 2036, the number of residential consumers is forecast to increase 17.7 percent to 328,774. The percentage of total residential consumers served is forecast to decline slightly in the year 2036 to 94.1%.

In 2003, 4.9% were Commercial and Other consumers compared to 5.6% in 2013. The total number of consumers in this sector grew from 11,755 to 16,717 during this period, representing a growth of 4.2%. The percentage of Commercial and Other sector in the year 2036 is forecast to be 5.8 percent, similar to the present mix. The number of consumers in this class is forecast to increase 22.2% to 20,435 in 2036.

The total number of consumers from the Industrial sector, which is defined as loads requiring transformation greater than 1,000 kVA, increased from 150 to 206 during the 2003 through 2013 period, for a net gain of 37 percent. The forecast number of 193 consumers in the year 2036 indicates an annual decrease of 0.3 percent.

The proportions of the aggregated member energy sales are different from the consumer mix. The residential class proportion of sales decreased from 63.9% in 2003 to 59.9% in 2013 due primarily to a large increase in sales to the Industrial Sector. The actual member system residential energy sales increased 26.2% from 3,243 GWh in 2003 to 4,092 GWh in 2013. The year 2036 residential sales forecast is 5,184 GWh – 60.6% of total sales.

Hoosier Energy experienced significant growth in sales to the Industrial classification between 2003 and 2013. Energy sales increased 55.7% from 1,128 GWh in 2003 to 1,756 GWh in 2013. The portion of total sales to this sector increased from 22.2% in 2003 to 25.7% in 2013. Total energy sales proportion is forecast to be 24.9% (2,132 GWh) for the year 2036.

The proportion of sales to the Commercial and Other sector increased from 13.9% in 2003 to 14.4% in 2013. Actual sales increased from 705 GWh in 2003 to 979 GWh in 2013, for an overall increase of38.8 percent. Total energy sales of this class are forecast to be 1,243 GWh in 2036, or 14.5 percent of total sales.

In aggregate, member-system energy sales increased 34.5 percent from 5,076 GWh in 2003 to 6,827 GWh in 2013. The member-system energy sales forecast of 8,559 GWh for 2036 represents an increase of 25.4% from the 2013 value.

[1] Historical statistics prior to 2011 do not include the addition of Wayne-White Counties Electric Cooperative. Future forecasts include the addition of Wayne-White.

3 Resource Changes since the 2014 Integrated Resource Plan

As part of normal business operations, Hoosier Energy has made a number of resource decisions since the 2014 IRP was filed. These decisions include both resources that were included in the 2014 IRP, but are no longer a part of Hoosier Energy's Capacity Expansion Plan (Plan) and resources that have been added to the Plan since 2014.

1. Frank E. Ratts Generating Station Retirement – At the time of the 2014 IRP filing, Hoosier Energy had suspended operations at one of the Ratts units, which was not included as an active generating resource in the IRP. Subsequent to the IRP, both units were retired in 2015.

2. Unit Contingent Sale – The 2014 IRP assumed a 200 MW Unit Contingent Sale from the Merom station. Based upon results of a 2016 request for proposals, market conditions and other risk factors, Hoosier Energy now plans to retain that capacity for the benefit of member systems. Therefore, the 200 MW sale is no longer included in the Plan.

3. Renewable Resources - The Hoosier Energy Board of Directors adopted a Renewable Energy Program (Board Policy 5-2) that defines targets and evaluation criteria for renewable projects. This policy was revised in 2014 setting a target of obtaining 10% of member energy requirements from renewable resources by 2025. Below are changes to the renewable resource portfolio since the 2014 IRP filing:

    a. The Osprey Point Renewable Energy Station has been removed as an active generating resource. This resource, which commenced operations in 2013, was idled in September 2016 primarily due to fuel supply issues and challenging market conditions. The Osprey Point facility remains a future resource option but is not included in the 2016 Capacity Expansion Plan.

    b. Hoosier Energy included two 4 MW landfill gas units as future resources in the 2014 IRP. Hoosier Energy no longer plans to construct these resources.

    c. The 2014 IRP included a 50 MW Wind PPA beginning in 2017. Subsequently, Hoosier Energy entered into a contract with EDP Renewables for 75 MW of capacity and energy from the Meadow Lake Wind Farm, which is located in White County, Indiana. The PPA is structured such that Hoosier Energy will receive the first 25 MW beginning in 2018 and the remaining 50 MW in 2020.

Transmission Resources

Hoosier Energy cooperates with all utilities within the Midcontinent ISO as well as our regional reliability council, ReliabilityFirst Corporation (RFC), to ensure that system changes are compatible with an orderly, economic and reliable development of the entire grid.

Hoosier Energy currently has physical interconnections with the following utilities:

- Big Rivers Electric Corp. (Big Rivers)
- Duke Energy Indiana
- Vectren
- Indianapolis Power & Light Company (IPL)
- Ameren

Hoosier Energy's transmission system consists of more than 1,700 miles of transmission line at 69 kilovolts (kV), 138 kV, 161 kV, and 345 kV. Approximately 56 percent of the member systems' power requirements are delivered to Hoosier Energy substations and delivery points using the transmission facilities of Duke Energy Indiana, Vectren, IPL and Ameren. The remainder is delivered through Hoosier Energy's transmission facilities.

Hoosier Energy's system presently includes twenty-four primary substations and approximately 350 distribution substations/delivery points. The distribution substations that serve the member systems are owned in part by Hoosier Energy and the member system. Hoosier Energy owns all the high voltage equipment, transformers, regulators, metering, the low voltage bus disconnect, all associated structures, the property and all in-ground fixtures (foundations, grounding, fencing, etc.). The member systems own the low voltage equipment and structures used for the service to the distribution circuits. Hoosier Energy performs the required maintenance on the entire substation and is responsible for upgrading of the transformer, etc., to meet increased requirements. There have been no substantial changes to Hoosier Energy's transmission system since the 2014 IRP.

Capacity Expansion Plan

Table 4 presents Hoosier Energy's Capacity Expansion Plan for the period from 2017 through 2036. This table compares the Summer Peak Demand requirements, as determined through Hoosier Energy's load forecasting, to Hoosier Energy's existing capacity resources. Table 4 demonstrates that, absent the acquisition of additional resources, Hoosier Energy will have a need for additional capacity requirements during the Summer months of the forecasted period in 2023 - 2024.

Capacity Expansion Plan - Summer Peak

	2017	2018	2020	2022	2024	2026	2028	2030	2032	2034	2036
Peak Demand											
Demand Forecast (1)	1,583	1,597	1,627	1,669	1,702	1,732	1,762	1,785	1,818	1,852	1,886
Demand Response/Energy Efficienc	(44)	(47)	(51)	(50)	(56)	(59)	(61)	(63)	(65)	(69)	(72)
Reserve Requirement (2)	120	121	123	126	128	130	133	134	137	139	141
Peak Requirement	1,659	1,671	1,699	1,745	1,774	1,803	1,834	1,856	1,890	1,922	1,955
Resources (MW)											
Merom	980	980	980	980	980	980	980	980	980	980	980
Power Purchase	250	150	150	150	50	0	0	0	0	0	0
Holland	312	312	312	312	312	312	312	312	312	312	312
Worthington	167	167	167	167	167	167	167	167	167	167	167
Lawrence	175	175	175	175	175	175	175	175	175	175	175
Renewables (3)	99	124	149	149	149	224	224	245	241	241	266
Unit Contingent Sales	(276)	0	0	0	0	0	0	0	0	0	0
Adj. for Forced Outage Rate (4)	(158)	(207)	(225)	(225)	(225)	(289)	(292)	(309)	(305)	(305)	(327)
Total Resources Adjusted	1,549	1,701	1,708	1,708	1,608	1,569	1,566	1,570	1,570	1,570	1,573
Total Resources minus Peak Req.											
Excess / (Deficit)	(110)	30	9	(38)	(167)	(235)	(268)	(287)	(320)	(352)	(383)

1 2015 Power Requirements Study Base Case Summer Peak Demand - Without Demand Response/Energy Efficiency

2 Assumed long-term Midwes 7.80%

3 Estimated Renewable Resources

4 Based upon current MISO capacity rules and plant performance both of which are subject to future changes.

Table 4: Summer Peak Demand Requirements and Planned Resources

4 Assessment of Resource Options

For this update of the 2014 IRP, Hoosier Energy retained the services of GDS Associates to perform an assessment of current and future resource options. This assessment identifies potential resources, and the associated cost and operational parameters to be included in the integrated system modeling process. Hoosier Energy's resource assessment and resource integration analysis was produced using the Strategist Integrated Planning System. This model, which is licensed to GDS Associates by ABB, has the capability to simulate production operations and develop least cost expansion plans. The production operations simulation establishes the optimal dispatch of generating resources and calculates the associated costs.

The development of least-cost expansion plans includes comparisons of all combinations of potential resource additions to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. Hoosier Energy's existing and currently planned generating resources were modeled using the Strategist Generation and Fuel ("GAF") module. Potential future resources were modeled using the GAF and the Proview ("PRV") modules. (The PRV module of Strategist facilitates, among other things, the calculation of capital costs associated with future units.)

The existing and future resources were dispatched against the PRS Load Forecast. The PRS Forecast was modeled using the Strategist Load Forecast Adjustment ("LFA") module. Cost and performance data contained in this portion of the IRP update will be used to assemble a set of base case assumptions for use in the modeling process. Supply related assumptions that may vary between the Base Case and sensitivity cases include: (1) fuel prices, (2) natural gas prices, (3) load growth, (4) emission costs, (5) renewable resource costs, (6) capital costs and (7) presence of CO_2 emission costs.

Hoosier Energy's Existing Supply-Side Resources

The following supply-side resources were incorporated into Hoosier Energy's assessment of resource options:

Merom – Merom units 1 and 2 are coal units with capacities of 491 MW and 489 MW, respectively. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Holland – Holland is a gas unit with a capacity of 625 MW. Hoosier Energy owns 50% of the facility in a partnership with Wabash Valley Power Association. All facility-related costs are shared equally between the two entities. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Worthington – The Worthington units 1-4 are gas units, each with a capacity of approximately 41.5 MW. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Lawrence – The Lawrence Generating Station consists of 6 units, with a total capacity of 258 MW. Hoosier Energy owns two-thirds of the units, with Wabash Valley Power Associatoion owning the other one-third share. All facility-related costs are shared proportionally between the two entities. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Purchased Power Agreement – Hoosier Energy currently has three purchased power contracts in place with Duke Energy Indiana. Two of the contracts are 100 MW. One terminates at the end of 2017 and the other terminates at the end of 2023. The contracts require that Hoosier Energy purchase a minimum of 65% of the total annual contract MWh, which provides optionality. Hoosier Energy has also entered into an additional purchased power contract that began in 2016, which provides the same optionality as the other contracts. This contract will provide Hoosier Energy with 50 MW, and will terminate at the end of 2025. Additional information regarding PPA costs is included in Appendix A.

Clark-Floyd – Clark-Floyd is a landfill gas unit with a capacity of 4 MW. For purposes of this IRP update, the unit is expected to retire at the end of 2027. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Story County – Story County is a 25 MW Wind PPA. The PPA contract is assumed to expire April 30, 2019. Additional information regarding PPA costs is included in Appendix A.

Livingston - Livingston is a landfill gas unit with a capacity of 15.2 MW. For purposes of this IRP update, the unit is expected to retire at the end of 2031. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Orchard Hills – Orchard Hills is a landfill gas unit with a capacity of 16 MW. Pertinent information regarding Variable O&M rate, heat rate and emissions rates are included in Appendix A.

Dayton Hydro – Dayton Hydro is a hydro PPA with a capacity of 3.6 MW. For purposes of this IRP, the PPA is expected to expire at the end of 2031. Additional information regarding PPA costs is included in Appendix A.

Rail Splitter – Rail Splitter is a 25 MW Wind PPA with expected annual generation of 74,000 MWh per year. Additional information regarding PPA costs is included in Appendix A.

Solar – Hoosier Energy's Solar resources will equal 10 MW by mid-2017 with expected annual generation of 20,000 MWh per year. Additional information regarding PPA costs is included in Appendix A.

Meadow Lake Wind PPA – The Meadow Lake Wind PPA is expected to start in 2018. The PPA will provide 25 MW of capacity in 2018 and an additional 50 MW of capacity beginning in 2020. The full PPA is expected to provide annual generation of 175,000 MWh. Additional information regarding PPA costs is included in Appendix A.

Renewable Resources – In addition to the individual supply-side resources described above, Hoosier Energy also assumed that it would acquire sufficient renewable resources to meet the revised Board Policy target of 10% of member load by 2025 and continuing thereafter. The assumed annual energy additions from renewable resources are provided in the table below:

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Additional Renewable Resources (MWh)	0	-	-	-	-	-	-	-	225,000	225,000
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Additional Renewable Resources (MWh)	225,000	225,000	300,000	300,000	300,000	300,000	300,000	300,000	375,000	375,000

Table 5: Forecasted Annual Renewable Resource Energy Additions (MWh)

Supply-Side Resource Alternatives

Supply-side resources typically include utility-owned generating capacity and/or purchases of power from other entities. Supply-side resources are distinguished from demand-side resources which are used to reduce energy consumption, or shift it to off-peak times, using energy efficient equipment and/or practices. Traditional supply-side resources include those that have historically been used to serve electric needs, as well as advanced or modified versions of these resources that have been developed or are expected to be developed during the term of the study period.

For the development of Hoosier Energy's IRP update, a list of traditional supply-side resources was compiled. This list of resources defines the options that the model is able to choose in order to meet planning reserve criteria. The list of potential additions includes traditional supply-side options and renewable supply-side options. The list includes options that are typically included in potential resource assessments and represent generic generating assets. Selection of a particular type of resource from this list would indicate the type of capacity, rather than a specific asset, that would best serve new resource needs.

Potential capacity additions that were analyzed for this IRP update are generic in nature in the sense that as Hoosier Energy approaches a time of capacity need, costs and availability of technically- and economically feasible alternatives will be assessed in great detail to ensure the optimum technology is chosen to fill actual needs. New capacity selections shown in each of the planning cases are indicative and could be supplied through participation in jointly-owned units, bilateral capacity purchases, or self-build options which could include either traditional or distributed generation options.

The complete list of options, along with operating characteristics and costs are shown in the table below. Further discussion of each option immediately follows the table. Capital costs and operating parameters (both characteristics and costs) were developed by Hoosier Energy. New resource capital cost obligations were modeled using an estimated cost of capital of 5%.

Potential Resource	Type	Capital Cost (2012 $/kW)	Capacity (MW)	Variable O&M (2012 $/MWh)	Energy Cost (2017 $/MWh)	Heat Rate (MMBtu/MWh)	Forced Outage Rate (%)	SO2 Emissions (lbs/MMBtu)	NOx Emissions (lbs/MMBtu)	CO2 Emissions (lbs/MMBtu)
Conventional CC	Gas	$ 917	100.0	$ 3.60		7.05	10.00%	0.01	0.001	117
Advanced CT	Gas	$ 676	100.0	$ 10.37		10.85	10.00%	0.03	0.001	117
Wind PPA	PPA		50.0		$ 40.00		60.00%			
Solar PPA	PPA		10.0		$ 55.00		75.00%			
Contract Extension 2018			100.0							
Contract Extension 2024			100.0							
Contract Extension 2026			50.0							

Table 6: Modeled Supply-Side Resource Alternative Assumptions

Conventional Combined Cycle (100 MW) - The CC unit is sized at 100 MW and has a capital cost of $917/kW and variable O&M rate of $3.60, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 7.05 MMBtu/MWh with a forced outage rate of 10%. Its SO2 emissions rate is 0.01 lbs/MMBtu, NOx emissions rate is 0.001 lbs/MMBtu, and CO2 emissions rate is 117 lbs/MMBtu.

Advanced Combustion Turbine (100 MW) - The CT unit is sized at 100 MW and has a capital cost of $676/kW and variable O&M rate of $10.37, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 10.85 MMBtu/MWh and has a forced outage rate of 10%. Its SO2 emissions rate is 0.03 lbs/MMBtu, NOx emissions rate is 0.001 lbs/MMBtu, and CO2 emissions rate is 117 lbs/MMBtu.

Wind PPA (50 MW) - The Wind PPA is sized at 50 MW and has an estimated energy cost of $40/MWh in 2016 dollars. The energy costs are escalated annually at an inflation rate of 2 percent. The PPA has a forced outage rate of 60%.

Solar PPA (10 MW) - The Solar PPA is sized at 10 MW and has an estimated energy cost of $55/MWh in 2016 dollars. The energy costs are escalated annually at an inflation rate of 2 percent. The PPA has a forced outage rate of 75%. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. This option is available beginning in 2016.

Contract Extension 2018 (100 MW) – This alternative is assumed to be an extension of the 100 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2017. Additional information regarding assumed PPA costs is included in Appendix A. For purposes of this IRP update, this option is only assumed to be available from 2018 to 2023.

Contract Extension 2024 (100 MW) – This alternative is assumed to be an extension of the 100 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2023. Additional information regarding assumed PPA costs is included in Appendix A. For purposes of this IRP update, this option is only assumed to be available from 2024 to 2025.

Contract Extension 2026 (50 MW) – This alternative is assumed to be an extension of the 50 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2025. Additional information regarding assumed PPA costs is included in Appendix A. For purposes of this IRP update, this option is only assumed to be available from 2026 to 2027.

Hoosier Energy's participation in the MISO market also defines another supply-side alternative. In the integrated modeling portion of the IRP development, market capacity and market energy will be included as potential resources. For this IRP update, Hoosier Energy limited the amount of potential annual market purchases or sales to 20 percent of that year's native load. It should be noted that Hoosier Energy does not approach the 20 percent threshold in any of the modeled portfolio results. Market prices will be discussed later in this report.

Fuel Price Assumptions

Hoosier Energy purchased the ABB Power Reference Case Electricity and Fuel Price Outlook (Midwest, Spring 2016) in order to obtain projections of fuel, market, and emission cost rates. Hoosier Energy provided estimates of coal prices for existing units for years 2017-2020. The coal prices were then escalated at the same growth rate as ABB's delivered coal price forecast for the MISO-Indiana region, adjusted for inflation. ABB's natural gas forward curve assumptions were used for both Henry Hub and Chicago with Hoosier Energy delivery costs added. The following table shows fuel price projections that will be used in the modeling process. Coal prices are assumed to remain constant during all months of each year. Gas prices vary; prices shown below are simple averages of projected monthly prices. The fuel and market price assumptions used in the Strategist modeling are located in Appendix B.

Costs of Emissions

There is much uncertainty currently with respect to costs associated with emissions from generating resources. Hoosier Energy is providing the emission costs assumptions in Appendix B for the period from 2017 through 2036. NOx and SO2 cost rates were obtained from the ABB Electricity and Fuel Price Outlook. Assumed carbon prices were provided by Hoosier Energy.

Market and Associated Prices

ABB's hourly market prices representing a typical week for each month in years 2017 - 2036 were used. The market price cost assumptions are provided in Appendix B for the base case and each sensitivity.

Demand-Side Resources

The demand-side resource options that are incorporated into the load forecast employed by Hoosier Energy were selected and developed as part of the 2013 GDS energy efficiency and demand response study, which, at the time of modeling, was the most recent update of the study.

In addition, Hoosier Energy provided updated energy efficiency and demand-side resource assumptions to GDS for a 2016 update of the study. Based upon the updated assumptions, an additional 3.5 MW of DSM and EE was selected in 2017 in some of the Strategist scenarios.

Strategist Results

Strategist simulations were produced for a base case and sensitivity cases. The base case was produced using base expectations of load and energy growth, and base expectations of fuel price growth. Sensitivity cases were developed as listed below.

1. High Market Prices – Base Case assumptions except that power and gas price growth were based on the high price forecasts contained in the ABB Electricity and Fuel Price Outlook.
2. Low Market Prices – Base Case assumptions except that power and gas price growth were based on the low price forecasts contained in the ABB Electricity and Fuel Price Outlook.
3. High Load Growth – Base Case assumptions except that Hoosier Energy's high load and energy forecasts were modeled. Hoosier Energy's high load growth assumptions are provided in Table 2, located in Section 2.
4. Low Load Growth – Base Case assumptions except that Hoosier Energy's low load and energy forecasts were modeled. Hoosier Energy's low load growth assumptions are provided in Table 3, located in Section 2.
5. High Renewable Prices – Base Case assumptions except new wind and solar prices were increased by 25 percent above Base Case assumptions.
6. Low Renewable Prices – Base Case assumptions except new wind and solar prices were reduced by 10 percent below Base Case assumptions.
7. CO2 Prices – A price was placed on CO2 emissions, with estimates on impacts to market and PPA prices.
8. High Capital Expenditure Costs – Overnight costs for Combined Cycle and Combustion Turbine construction were increased by 25% above the Base Case.

GDS Associates collaborated with Hoosier Energy in developing an Environmental Future scenario, under which carbon limits were imposed on Hoosier Energy's emissions and new wind resources were limited to a total of 400 MW over the 2017 – 2036 timeframe. New wind resources were limited to 400 MW in the Environmental Future Base Case as it was assumed that was the limit of Hoosier Energy's potential opportunities. Hoosier Energy also modeled sensitivity cases in which the potential new wind resource availability was doubled to 800 MW. Sensitivity cases were developed as listed below.

1. Environmental Future Additional Wind – Environmental Future base case assumptions with new wind resource limit increased to 800 MW over the 2017 – 2036 timeframe.
2. Environmental Future Solar Limit – Environmental Future base case assumptions with installation of new solar resources not allowed in back-to-back years.

3. Environmental Future Additional Wind/Solar Limit - Environmental Future base case assumptions with new wind resource limit increased to 800 MW over the 2017 – 2036 timeframe and installation of new solar resources not allowed in back to back years.
4. Environmental Future Base Case with Low Market Conditions – Environmental Future Base Case assumptions except that power and gas price growth were based on the low price forecasts contained in the ABB Electricity and Fuel Price Outlook.
5. Environmental Future Additional Wind with Low Market Conditions - Environmental Future base case assumptions with new wind resource limit increased to 800 MW over the 2017 – 2036 timeframe except that power and gas price growth were based on the low price forecasts contained in the ABB Electricity and Fuel Price Outlook.
6. Environmental Future Solar Limit with Low Market Conditions - Environmental Future base case assumptions with installation of new solar resources not allowed in back-to-back years. Power and gas price growth were based on the low price forecasts contained in the ABB Electricity and Fuel Price Outlook.
7. Environmental Future Additional Wind/Solar Limit with Low Market Conditions - Environmental Future base case assumptions with new wind resource limit increased to 800 MW over the 2017 – 2036 timeframe and installation of new solar resources not allowed in back to back years. Power and gas price growth were based on the low price forecasts contained in the ABB Electricity and Fuel Price Outlook.

The following tables show the five lowest cost expansion plans (from the top 100 plans) selected by the Strategist model for the Base Case and Environmental Future scenarios and each of the sensitivity cases.

Two of these tables (the High Load Scenario and Environmental Future – Solar Limit Scenario) include a sixth case, which shows a selection of a Combined Cycle unit in 2024. This case is included in recognition of the fact that there are a number of entities in the planning stages of developing new CCs in and around Indiana. Comparing this case to those selected by Strategist as one of the top 5 shows the minor differences in NPV costs.

It should also be noted that, in a number of the Environmental Future sensitivity scenarios, the Strategist model selected the Duke PPA extension options in 2024 and 2026. Hoosier Energy is skeptical of these results and will continue to examine and fine tune the assumptions prior to the 2017 IRP filing.

Base Case – Lowest Cost Plans

The Base Case lowest cost plans include a mix of Combustion Turbine, Combined Cycle and Wind PPA purchases. The first incremental supply-side resource will be required in 2024. The 100 scenario iterations have an NPV range of $4.31 billion - $4.315 billion over the period. It should be noted that the NPV's of the five least expensive base case plans are within 0.01 percent of each other.

	Base Case Plan Rank 1		Base Case Plan Rank 2		Base Case Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022						
2023						
2024	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100	Wind	100
2025						
2026						
2027	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2028						
2029						
2030	Wind	100	Wind	100	Wind	100
2031	Wind	100	Wind	100	Wind	100
2032	Wind	100	Wind	100	Wind	100
2033						
2034						
2035						
2036	Combined Cycle	100	Combined Cycle	100	Combustion Turbine	100
			Solar	10		
Scenario NPV ($000)		$ 4,308,258.00		$ 4,308,356.50		$ 4,308,465.50
Percentage Above Low Cost Plan				0.00%		0.00%

	Base Case Plan Rank 4		Base Case Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022				
2023				
2024	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100
2025				
2026				
2027	Combined Cycle	100	Combined Cycle	100
2028				
2029				
2030	Wind	100	Wind	100
2031	Wind	100	Wind	100
2032	Wind	100	Wind	100
2033				
2034				
2035	Solar	10		
2036	Combined Cycle	100	Combustion Turbine	100
	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,308,546.50		$ 4,308,594.50
Percentage Above Low Cost Plan		0.01%		0.01%

High Load Scenario - Lowest Cost Plans

The High Load scenario lowest cost plans include a mix of Combustion Turbine, Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of $4.926 billion - $4.931 billion over the period. It should be noted that the NPV's of the five least expensive base case plans vary slightly from each other.

	High Load Plan Rank 1		High Load Plan Rank 2		High Load Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
2023	Wind	100	Wind	100	Wind	100
2024	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100	Wind	100
2025	Wind	100	Wind	100	Wind	100
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027						
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2029	Wind	100	Wind	100	Wind	100
2030						
2031						
2032	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2033						
2034					Solar	10
2035	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2036	Solar	10			Solar	10
Scenario NPV ($000)		$ 4,926,354.00		$ 4,926,375.00		$ 4,926,428.50
Percentage Above Low Cost Plan				0.00%		0.00%

	High Load Plan Rank 4		High Load Plan Rank 5		High Load Plan Rank 56	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
2023	Wind	100	Wind	100	Wind	100
2024	Combustion Turbine	100	Combustion Turbine	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
2025	Wind	100	Wind	100	Wind	100
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027						
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2029	Wind	100	Wind	100		
2030					Wind	100
2031						
2032	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2033						
2034	Solar	10				
2035	Combined Cycle	100	Combustion Turbine	100	Combustion Turbine	100
	Solar	10				
2036	Solar	10	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,926,507.00		$ 4,926,564.50		$ 4,929,552.00
Percentage Above Low Cost Plan		0.00%		0.00%		**0.06%**

Low Load Scenario - Lowest Cost Plans

The Low Load scenario lowest cost plans include a mix of Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2026. The 100 scenario iterations have an NPV range of $3.671 billion - $3.684 billion over the period. It should be noted that the NPV's of the five least expensive base case plans vary slightly from each other.

	Low Load Plan Rank 1		Low Load Plan Rank 2		Low Load Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026	Wind	100	Wind	100	Wind	100
2027						
2028						
2029						
2030						
2031	Wind	100	Wind	100	Wind	100
2032						
2033	Wind	100	Wind	100	Wind	100
2034						
2035						
2036			Wind	100	Solar	10
Scenario NPV ($000)		$ 3,671,162.20		$ 3,671,205.20		$ 3,671,267.80
Percentage Above Low Cost Plan				0.00%		0.00%

	Low Load Plan Rank 4		Low Load Plan Rank 5	
Year	Addition	MW	Addition	MW
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026	Wind	100	Wind	100
2027				
2028				
2029				
2030				
2031	Wind	100	Wind	100
2032				
2033	Wind	100	Wind	100
2034				
2035			Solar	10
2036	Wind	100	Solar	10
	Solar	10		
Scenario NPV ($000)		$ 3,671,314.20		$ 3,671,493.00
Percentage Above Low Cost Plan		0.00%		0.01%

High Market Price Scenario - Lowest Cost Plans

The High Market Price scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of $4.394 billion - $4.406 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	High Market Prices Plan Rank 1		High Market Prices Plan Rank 2		High Market Prices Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
2025	Wind	100	Wind	100	Wind	100
2026	Solar	10	Solar	10	Solar	10
2027	Solar	10	Solar	10	Solar	10
2028	Solar	10	Solar	10	Solar	10
2029	Solar	10	Solar	10	Solar	10
2030	Solar	10	Solar	10	Solar	10
2031	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
			Solar	10		
2032	Solar	10	Solar	10	Solar	10
2033	Solar	10	Solar	10	Solar	10
2034	Solar	10	Solar	10	Solar	10
2035	Solar	10	Solar	10	Solar	10
2036	Solar	10	Solar	10		
Scenario NPV ($000)		$ 4,394,482.00		$ 4,394,501.50		$ 4,394,549.00
Percentage Above Low Cost Plan				0.00%		0.00%

	High Market Prices Plan Rank 4		High Market Prices Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100
2025	Wind	100	Wind	100
2026	Solar	10	Wind	100
			Solar	10
2027	Solar	10	Solar	10
2028	Solar	10	Solar	10
2029	Solar	10	Solar	10
2030			Solar	10
2031	Combined Cycle	100	Combined Cycle	100
			Solar	10
2032	Solar	10	Solar	10
2033	Solar	10	Solar	10
2034	Solar	10	Solar	10
2035	Solar	10	Solar	10
2036			Solar	10
Scenario NPV ($000)		$ 4,394,648.50		$ 4,394,720.50
Percentage Above Low Cost Plan		0.00%		0.01%

Low Market Price Scenario - Lowest Cost Plans

The Low Market Price scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2024. The 100 scenario iterations have an NPV range of $4.093 billion - $4.100 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	Low Market Prices Plan Rank 1		Low Market Prices Plan Rank 2		Low Market Prices Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2025	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2026						
2027						
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2029						
2030						
2031						
2032						
2033						
2034	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2035					Solar	10
2036			Solar	10	Solar	10
Scenario NPV ($000)		$ 4,093,303.80		$ 4,093,486.00		$ 4,093,859.80
Percentage Above Low Cost Plan				0.00%		0.01%

	Low Market Prices Plan Rank 4		Low Market Prices Plan Rank 5	
Year	Addition	MW	Addition	MW
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024	Combined Cycle	100	Combined Cycle	100
2025	Combined Cycle	100	Combined Cycle	100
2026				
2027				
2028	Combined Cycle	100	Combined Cycle	100
2029				
2030				
2031				
2032				
2033				
2034	Combined Cycle	100	Combined Cycle	100
			Solar	10
2035			Solar	10
2036	Wind	100	Solar	10
Scenario NPV ($000)		$ 4,094,284.80		$ 4,094,435.80
Percentage Above Low Cost Plan		0.02%		0.03%

<u>High Renewables Cost Scenario – Lowest Cost Plans</u>

The High Renewables Cost scenario lowest cost plans include a mix of Combined Cycle, Combustion Turbine, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2024. The 100 scenario iterations have an NPV range of $4.320 billion - $4.329 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	High Renewables Cost Plan Rank 1		High Renewables Cost Plan Rank 2		High Renewables Cost Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022						
2023						
2024	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
2025						
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027						
2028						
2029						
2030						
2031						
2032	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2033						
2034						
2035					Solar	10
2036			Solar	10	Solar	10
Scenario NPV ($000)		$ 4,320,133.00		$ 4,320,235.00		$ 4,320,556.50
Percentage Above Low Cost Plan				0.00%		0.01%

	High Renewables Cost Plan Rank 4		High Renewables Cost Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022				
2023				
2024	Combustion Turbine	100	Combined Cycle	100
2025				
2026	Combined Cycle	100	Combined Cycle	100
2027				
2028				
2029				
2030				
2031				
2032	Combined Cycle	100		
2033			Combined Cycle	100
2034				
2035				
2036	Wind	100		
Scenario NPV ($000)		$ 4,320,573.50		$ 4,320,663.00
Percentage Above Low Cost Plan		0.01%		0.01%

Low Renewables Cost Scenario – Lowest Cost Plans

The Low Renewables Cost scenario lowest cost plans include a mix of Combined Cycle, Combustion Turbine, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2023. The 100 scenario iterations have an NPV range of $4.277 billion - $4.281 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	Low Renewables Cost Plan Rank 1		Low Renewables Cost Plan Rank 2		Low Renewables Cost Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022						
2023	Wind	100	Wind	100	Wind	100
2024	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100	Wind	100
2025	Wind	100	Wind	100	Wind	100
2026	Wind	100	Wind	100	Wind	100
2027						
2028						
2029						
2030						
2031	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2032						
2033	Solar	10	Solar	10	Solar	10
2034	Solar	10	Solar	10		
2035			Solar	10		
2036	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
Scenario NPV ($000)		$ 4,276,789.50		$ 4,276,804.00		$ 4,276,805.50
Percentage Above Low Cost Plan				0.00%		0.00%

	Low Renewables Cost Plan Rank 4		Low Renewables Cost Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022				
2023	Wind	100	Wind	100
2024	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100
2025	Wind	100	Wind	100
2026	Wind	100	Wind	100
2027				
2028				
2029				
2030				
2031	Combined Cycle	100	Combined Cycle	100
2032			Solar	10
2033			Solar	10
2034			Solar	10
2035			Solar	10
2036	Combined Cycle	100	Solar	10
Scenario NPV ($000)		$ 4,276,842.00		$ 4,276,847.00
Percentage Above Low Cost Plan		0.00%		0.00%

High Capital Expenditures Costs Scenario – Lowest Cost Plans

The High Capital Expenditures Cost scenario lowest cost plans include a mix of Combined Cycle, Combustion Turbine, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2024. The 100 scenario iterations have an NPV range of $4.329 billion - $4.333 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	Capex Increase Plan Rank 1		Capex Increase Plan Rank 2		Capex Increase Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021						
2022						
2023						
2024	Wind	100	Wind	100	Wind	100
2025	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100	Wind	100
2026	Wind	100	Wind	100	Wind	100
2027	Wind	100	Wind	100	Wind	100
2028						
2029						
2030						
2031	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2032						
2033						
2034						
2035					Solar	10
2036	Solar	10			Solar	10
Scenario NPV ($000)		$ 4,329,132.50		$ 4,329,137.00		$ 4,329,137.50
Percentage Above Low Cost Plan				0.00%		0.00%

	Capex Increase Plan Rank 4		Capex Increase Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022				
2023				
2024	Wind	100	Wind	100
2025	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100
2026	Wind	100	Wind	100
2027	Wind	100	Wind	100
2028				
2029				
2030				
2031	Combined Cycle	100	Combined Cycle	100
2032				
2033			Solar	10
2034	Solar	10	Solar	10
2035	Solar	10	Solar	10
2036	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,329,165.50		$ 4,329,232.00
Percentage Above Low Cost Plan		0.00%		0.00%

Carbon Price Scenario – Lowest Cost Plans

The Carbon Price scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of \$5.414 billion - \$5.431 billion over the period, which was the highest cost scenario. The NPV's of the five least expensive base case plans vary slightly from each other.

	CO2 Price Plan Rank 1		CO2 Price Plan Rank 2		CO2 Price Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021			Solar	10		
2022	Wind	100	Wind	100	Wind	100
	Solar	10	Solar	10	Solar	10
2023	Wind	100	Wind	100	Wind	100
	Solar	10	Solar	10	Solar	10
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
	Solar	10	Solar	10	Solar	10
2025	Wind	100	Wind	100	Wind	100
	Solar	10	Solar	10	Solar	10
2026	Solar	10	Solar	10	Solar	10
2027	Solar	10	Solar	10	Solar	10
2028	Solar	10	Solar	10	Solar	10
2029	Solar	10	Solar	10	Solar	10
2030	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10	Solar	10
2031	Solar	10	Solar	10	Solar	10
2032	Solar	10	Solar	10	Solar	10
2033	Solar	10	Solar	10	Solar	10
2034	Solar	10	Solar	10	Solar	10
2035	Solar	10	Solar	10	Solar	10
2036	Solar	10	Solar	10		
Scenario NPV (\$000)		\$ 5,414,051.50		\$ 5,414,133.00		\$ 5,414,225.50
Percentage Above Low Cost Plan				0.00%		0.00%

	CO2 Price Plan Rank 4		CO2 Price Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021				
2022	Wind	100	Wind	100
	Solar	10	Solar	10
2023	Wind	100	Wind	100
	Solar	10	Solar	10
2024	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100
	Solar	10	Solar	10
2025	Wind	100	Wind	100
	Solar	10	Solar	10
2026	Solar	10	Solar	10
2027	Solar	10	Solar	10
2028	Solar	10	Solar	10
2029	Solar	10	Solar	10
2030	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10
2031	Solar	10	Solar	10
2032	Solar	10	Solar	10
2033	Solar	10	Solar	10
2034	Solar	10	Solar	10
2035	Solar	10	Solar	10
2036	Combined Cycle	100	Combined Cycle	100
	Solar	10		
Scenario NPV (\$000)		\$ 5,414,291.50		\$ 5,414,364.00
Percentage Above Low Cost Plan		0.00%		0.01%

Environmental Future Base Case – Lowest Cost Plans

The Environmental Future Base Case scenario lowest cost plans include a mix of Combined Cycle, Duke PPA Extension, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2020. The 100 scenario iterations have an NPV range of $4.753 billion - $4.830 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	Environmental Future Base Case Plan Rank 1		Environmental Future Base Case Plan Rank 2		Environmental Future Base Case Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020	Wind	100	Wind	100	Wind	100
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	PPA Extension	100	PPA Extension	100	PPA Extension	100
2025						
2026	PPA Extension	50	PPA Extension	50	PPA Extension	50
2027	Solar	10	Solar	10	Solar	10
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10	Solar	10
2029	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2030	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2031	Solar	10	Solar	10	Solar	10
2032	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2033	Solar	10	Solar	10	Solar	10
2034	Solar	10	Solar	10	Solar	10
2035	Solar	10	Solar	10	Solar	10
2036	Combined Cycle	100			Combined Cycle	100
					Solar	10
Scenario NPV ($000)		$ 4,753,438.00		$ 4,753,505.50		$ 4,753,520.00
Percentage Above Low Cost Plan				0.00%		0.00%

	Environmental Future Base Case Plan Rank 4		Environmental Future Base Case Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020	Wind	100	Wind	100
2021	Wind	100	Wind	100
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	PPA Extension	100	PPA Extension	100
2025				
2026	PPA Extension	50	PPA Extension	50
2027	Solar	10	Solar	10
2028	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10
2029	Combined Cycle	100	Combined Cycle	100
2030	Combined Cycle	100	Combined Cycle	100
2031			Solar	10
2032	Combined Cycle	100	Combined Cycle	100
2033			Solar	10
2034			Solar	10
2035			Solar	10
2036			Solar	10
Scenario NPV ($000)		$ 4,753,612.50		$ 4,754,743.50
Percentage Above Low Cost Plan		0.00%		0.03%

Environmental Future – Additional Wind Scenario – Lowest Cost Plans

The Environmental Future-Additional Wind scenario lowest cost plans include a mix of Combined Cycle, Combustion Turbine, Duke PPA Extension, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2019. The 100 scenario iterations have an NPV range of $4.540 billion - $4.581 billion over the period. The NPV's of the five least expensive base case plans vary slightly from each other.

	Environmental Future - Additional Wind Plan Rank 1		Environmental Future - Additional Wind Plan Rank 2		Environmental Future - Additional Wind Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019	Wind	100			Wind	100
2020	Wind	100	Wind	100	Wind	100
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
	Solar	10			Solar	10
2023	Wind	100	Wind	100	Wind	100
			Solar	10		
2024	Wind	100	Wind	100	Wind	100
			PPA Extension	100		
2025	Wind	100	Wind	100	Wind	100
2026	Wind	100	Wind	100	Wind	100
	PPA Extension	50			PPA Extension	50
2027	Solar	10	Wind	100	Solar	10
2028	Solar	10			Solar	10
2029	Solar	10	Combined Cycle	100	Solar	10
2030	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2031	Combined Cycle	100			Combined Cycle	100
2032						
2033			Solar	10		
2034	Solar	10			Solar	10
2035			Solar	10		
2036	Solar	10	Combustion Turbine	100		
			Solar	10		
Scenario NPV ($000)		$ 4,539,626.50		$ 4,540,624.50		$ 4,540,670.00
Percentage Above Low Cost Plan				0.02%		0.02%

	Environmental Future - Additional Wind Plan Rank 4		Environmental Future - Additional Wind Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019	Wind	100		
2020	Wind	100	Wind	100
2021	Wind	100	Wind	100
2022	Wind	100	Wind	100
	Solar	10		
2023	Wind	100	Wind	100
			Solar	10
2024	Wind	100	Wind	100
			PPA Extension	100
2025	Wind	100	Wind	100
2026	Wind	100	Wind	100
	PPA Extension	50		
2027	Solar	10	Wind	100
2028	Solar	10		
2029	Solar	10	Combined Cycle	100
2030	Combined Cycle	100	Combined Cycle	100
2031	Combined Cycle	100		
2032				
2033			Solar	10
2034	Solar	10		
2035	Solar	10	Solar	10
2036	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,541,087.50		$ 4,541,435.00
Percentage Above Low Cost Plan		0.03%		0.04%

Environmental Future Plan – Solar Limit Scenario – Lowest Cost Plan

The Environmental Future-Solar Limit scenario lowest cost plans include a mix of Combined Cycle, Duke PPA Extension, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2020. The 100 scenario iterations have an NPV range of $4.736 billion - $4.851 billion over the period. The NPV's of the five least expensive base case plans vary 0.11%.

	Environmental Future - Solar Limit Plan Rank 1		Environmental Future - Solar Limit Plan Rank 2		Environmental Future - Solar Limit Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020	Wind	100	Wind	100	Wind	100
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	PPA Extension	100	PPA Extension	100	PPA Extension	100
2025						
2026	PPA Extension	50	PPA Extension	50	PPA Extension	50
2027						
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2029	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Solar	10			Solar	10
2030	Combined Cycle	100			Combined Cycle	100
2031			Combined Cycle	100		
2032	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
					Solar	10
2033						
2034						
2035					Solar	10
2036					Combined Cycle	100
Scenario NPV ($000)		$ 4,735,721.50		$ 4,739,029.50		$ 4,740,171.50
Percentage Above Low Cost Plan				0.07%		0.09%

	Environmental Future - Solar Limit Plan Rank 4		Environmental Future - Solar Limit Plan Rank 5		Environmental Future - Solar Limit Plan Rank 96	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5		
2018						
2019						
2020	Wind	100	Wind	100	Wind	100
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
					Solar	10
2023	Wind	100	Wind	100		
2024	PPA Extension	100	PPA Extension	100	Combined Cycle	100
					PPA Extension	100
2025						
2026	PPA Extension	50	PPA Extension	50	PPA Extension	50
2027						
2028	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2029	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10		
2030	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2031					Combined Cycle	100
2032	Combined Cycle	100	Combined Cycle	100	Solar	10
	Solar	10	Solar	10		
2033					Solar	10
2034						
2035	Solar	10				
2036			Combined Cycle	100	Solar	10
Scenario NPV ($000)		$ 4,740,528.00		$ 4,740,880.50		$ 4,848,944.50
Percentage Above Low Cost Plan		0.10%		0.11%		**2.39%**

Environmental Future – Additional Wind/Solar Limit Scenario – Lowest Cost Plans

The Environmental Future - Additional Wind/Solar Limit scenario lowest cost plans include a mix of Combined Cycle, Combustion Turbine, Duke PPA Extension, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2020. The 100 scenario iterations have an NPV range of $4.540 billion - $4.590 billion over the period. The NPV's of the five least expensive base case plans vary 0.02%.

	Environmental Future - Additional Wind/Solar Limit Plan Rank 1		Environmental Future - Additional Wind/Solar Limit Plan Rank 2		Environmental Future - Additional Wind/Solar Limit Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020	Wind	100	Wind	100	Wind	100
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
	Solar	10	Solar	10	Solar	10
2024	Wind	100	Wind	100	Wind	100
	PPA Extension	100	PPA Extension	100	PPA Extension	100
2025	Wind	100	Wind	100	Wind	100
2026	Wind	100	Wind	100	Wind	100
2027	Wind	100	Wind	100	Wind	100
2028						
2029	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2030	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2031						
2032						
2033	Solar	10	Solar	10	Solar	10
2034			Solar	10		
2035	Solar	10	Solar	10	Solar	10
2036	Combustion Turbine	100	Solar	10	Solar	10
	Solar	10				
Scenario NPV ($000)		$ 4,540,624.50		$ 4,541,199.00		$ 4,541,435.00
Percentage Above Low Cost Plan				0.01%		0.02%

	Environmental Future - Additional Wind/Solar Limit Plan Rank 4		Environmental Future - Additional Wind/Solar Limit Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Enery Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020	Wind	100	Wind	100
2021	Wind	100	Wind	100
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
	Solar	10	Solar	10
2024	Wind	100	Wind	100
	PPA Extension	100	PPA Extension	100
2025	Wind	100	Wind	100
2026	Wind	100	Wind	100
2027	Wind	100	Wind	100
2028				
2029	Combined Cycle	100	Combined Cycle	100
2030	Combined Cycle	100	Combined Cycle	100
2031				
2032				
2033	Solar	10	Solar	10
2034				
2035	Solar	10	Solar	10
2036	Combined Cycle	100	Combined Cycle	100
	Solar	10		
Scenario NPV ($000)		$ 4,541,447.00		$ 4,541,480.00
Percentage Above Low Cost Plan		0.02%		0.02%

Environmental Future Base Case – Low Market Prices – Lowest Cost Plans

The Environmental Future Base Case – Low Market scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of $4.184 billion - $4.196 billion over the period. The NPV's of the five least expensive base case plans vary 0.02%.

	Environmental Future Base - Low Market Plan Rank 1		Environmental Future Base - Low Market Plan Rank 2		Environmental Future Base - Low Market Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017						
2018						
2019						
2020						
2021						
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
2025						
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2028						
2029					Solar	10
2030	Wind	100	Wind	100	Solar	10
2031					Wind	100
2032					Solar	10
2033					Solar	10
2034	Combined Cycle	100	Combined Cycle	100	Solar	10
2035						
2036			Solar	10	Combined Cycle	100
Scenario NPV ($000)		$ 4,183,587.00		$ 4,183,771.80		$ 4,184,119.50
Percentage Above Low Cost Plan				0.00%		0.01%

	Environmental Future Base - Low Market Plan Rank 4		Environmental Future Base - Low Market Plan Rank 5	
Year	Addition	MW	Addition	MW
2017				
2018				
2019				
2020				
2021				
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100
2025				
2026	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100
2028				
2029			Solar	10
2030	Wind	100	Solar	10
2031			Wind	100
2032			Solar	10
2033			Solar	10
2034	Combined Cycle	100	Solar	10
2035	Solar	10		
2036	Solar	10	Combined Cycle	100
			Solar	10
Scenario NPV ($000)		$ 4,184,150.50		$ 4,184,303.80
Percentage Above Low Cost Plan		0.01%		0.02%

Environmental Future – Additional Wind Scenario – Low Market Prices – Lowest Cost Plans

The Environmental Future-Additional Wind – Low Market scenario lowest cost plans include a mix of Combustion Turbine, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2021. The 100 scenario iterations have an NPV range of $4.231 billion - $4.248 billion over the period. The NPV's of the five least expensive base case plans vary 0.04%.

	Environmental Future - Additional Wind - Low Market Plan Rank 1		Environmental Future - Additional Wind - Low Market Plan Rank 2		Environmental Future - Additional Wind - Low Market Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018						
2019						
2020						
2021	Wind	100	Wind	100	Wind	100
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	Wind	100	Wind	100	Wind	100
2025	Wind	100	Wind	100	Wind	100
2026	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100	Wind	100
2027						
2028	Wind	100	Wind	100	Wind	100
2029						
2030						
2031						
2032						
2033	Wind	100	Wind	100	Wind	100
2034	Combustion Turbine	100	Combustion Turbine	100	Combustion Turbine	100
2035					Solar	10
2036			Solar	10	Solar	10
Scenario NPV ($000)		$ 4,231,047.00		$ 4,231,215.00		$ 4,231,568.00
Percentage Above Low Cost Plan				0.00%		0.01%

	Environmental Future - Additional Wind - Low Market Plan Rank 4		Environmental Future - Additional Wind - Low Market Plan Rank 5	
Year	Addition	MW	Addition	MW
2017	Energy Efficiency/Demand Response	3.5	Energy Efficiency/Demand Response	3.5
2018				
2019				
2020				
2021	Wind	100	Wind	100
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	Wind	100	Wind	100
2025	Wind	100	Wind	100
2026	Combustion Turbine	100	Combustion Turbine	100
	Wind	100	Wind	100
2027				
2028	Wind	100	Wind	100
2029				
2030				
2031				
2032				
2033	Wind	100	Wind	100
			Solar	10
2034	Combustion Turbine	100	Combustion Turbine	100
	Solar	10	Solar	10
2035	Solar	10	Solar	10
2036	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,232,120.00		$ 4,232,868.00
Percentage Above Low Cost Plan		0.03%		0.04%

Environmental Future – Solar Limit Scenario – Low Market Prices – Lowest Cost Plans

The Environmental Future - Solar Limit – Low Market scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of $4.177 billion - $4.196 billion over the period. The NPV's of the five least expensive base case plans vary 0.05%.

	Environmental Future - Solar Limit - Low Market Plan Rank 1		Environmental Future - Solar Limit - Low Market Plan Rank 2		Environmental Future - Solar Limit - Low Market Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017						
2018						
2019						
2020						
2021						
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
2025						
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2028						
2029						
2030	Wind	100	Wind	100	Wind	100
2031						
2032						
2033						
2034	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2035					Solar	10
2036			Solar	10	Solar	10
Scenario NPV ($000)		$ 4,176,527.50		$ 4,176,712.20		$ 4,177,091.00
Percentage Above Low Cost Plan				0.00%		0.01%

	Environmental Future - Solar Limit - Low Market Plan Rank 4		Environmental Future - Solar Limit - Low Market Plan Rank 5	
Year	Addition	MW	Addition	MW
2017				
2018				
2019				
2020				
2021				
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100
2025				
2026	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100
2028				
2029				
2030	Wind	100	Wind	100
2031				
2032				
2033			Solar	10
2034	Combined Cycle	100	Combined Cycle	100
	Solar	10	Solar	10
2035	Solar	10	Solar	10
2036	Solar	10	Solar	10
Scenario NPV ($000)		$ 4,177,671.20		$ 4,178,460.80
Percentage Above Low Cost Plan		0.03%		0.05%

<u>Environmental Future Plan – Addiitonal Wind/Solar Limit Scenario – Low Market Prices - Lowest Cost Plans</u>

The Environmental Future - Additional Wind/Solar Limit – Low Market scenario lowest cost plans include a mix of Combined Cycle, Wind PPA and Solar PPA purchases. The first incremental supply-side resource will be required in 2022. The 100 scenario iterations have an NPV range of $4.174 billion - $4.181 billion over the period. The NPV's of the five least expensive base case plans vary slightly.

	Environmental Future - Additional Wind/Solar Limit - Low Market Plan Rank 1		Environmental Future - Additional Wind/Solar Limit - Low Market Plan Rank 2		Environmental Future - Additional Wind/Solar Limit - Low Market Plan Rank 3	
Year	Addition	MW	Addition	MW	Addition	MW
2017						
2018						
2019						
2020						
2021						
2022	Wind	100	Wind	100	Wind	100
2023	Wind	100	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100	Wind	100
2025						
2026	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100	Combined Cycle	100
2028						
2029						
2030	Wind	100	Wind	100	Wind	100
2031						
2032						
2033						
2034	Wind	100	Wind	100	Wind	100
2035						
2036			Solar	10	Wind	100
Scenario NPV ($000)		$ 4,173,863.80		$ 4,174,039.00		$ 4,174,185.00
Percentage Above Low Cost Plan				0.00%		0.01%

	Environmental Future - Additional Wind/Solar Limit - Low Market Plan Rank 4		Environmental Future - Additional Wind/Solar Limit - Low Market Plan Rank 5	
Year	Addition	MW	Addition	MW
2017				
2018				
2019				
2020				
2021				
2022	Wind	100	Wind	100
2023	Wind	100	Wind	100
2024	Combined Cycle	100	Combined Cycle	100
	Wind	100	Wind	100
2025				
2026	Combined Cycle	100	Combined Cycle	100
2027	Combined Cycle	100	Combined Cycle	100
2028				
2029				
2030	Wind	100	Wind	100
2031				
2032				
2033				
2034	Wind	100	Wind	100
2035			Solar	10
2036	Wind	100	Solar	10
	Solar	10		
Scenario NPV ($000)		$ 4,174,359.20		$ 4,174,396.80
Percentage Above Low Cost Plan		0.01%		0.01%

5 Hoosier Energy's Short-Term Action Plan

Taking into account the changes in Hoosier Energy's load forecast and its supply-side and demand-side resource mix since the 2014 IRP filing, Hoosier Energy expects to have sufficient resources for the immediate future. In anticipation of future needs and consistent with a desire to continue to diversify the resource mix with cost-effective resources, Hoosier Energy will continue efforts to add demand-side and renewable resources as follows:

1. Hoosier Energy will use market purchases to meet short term needs during 2017. In addition, Hoosier Energy will continue to employ hedging strategies to reduce market price risk.
2. Hoosier Energy will continue to develop and implement cost effective demand response and energy efficiency programs in conjunction with member systems.
3. Hoosier Energy will continue to pursue cost-effective, renewable resources to achieve the Board target of 10% of member energy requirements by 2025. Hoosier Energy also expects increased interest from Commercial & Industrial customers to add renewable resources.
4. Hoosier Energy will continue to monitor and analyze potential environmental regulations that may impact intermediate and long-term operations.
5. Strategist modeling performed by GDS Associates indicates the next major resource increment is required around the years 2023/2024.
6. Hoosier Energy will perform additional analysis, including an assessment of existing resources, as part of the 2017 Integrated Resource Plan.

In addition, the wholesale power market remains an integral part of Hoosier Energy's resource plan. Purchases from and sales into the market will continue to be an appropriate and economical complement to Hoosier Energy existing resource mix.

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