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Appendix II.C WPL 2014 Integrated Resource Plan

Public Version

Wisconsin Power and Light

2014

Integrated Resource Plan

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1 INTRODUCTION

This is the 2014 Electric Integrated Resource Plan of Wisconsin Power and Light Company (WPL or Company), a wholly-owned subsidiary of Alliant Energy Corporation (Alliant Energy) and a public utility as defined in Wis. Stat. § 196.01(5) . WPL's 2014 Electric Integrated Resource Plan (Resource Plan or IRP) uses the Electric Generation Expansion Analysis System (EGEAS) model for the economic expansion plan analysis portion of the IRP. The base year for the EGEAS model is 2012 with a study period of 2013-2042 and a 35 year extension period.

This section provides an overview of the WPL system and IRP development, presents future industry considerations, and identifies anticipated filings that will incorporate the IRP. Sections 2 through 7 of this report describe the contents of the IRP.

- Section 2 Load Forecast
- Section 3 Demand-Side Management and energy Efficiency
- Section 4 Distributed Generation
- Section 5 Existing WPL Generating Resources
- Section 6 Load and Capability
- Section 7 Generation Resource Planning Alternatives
- Section 8 Resource Plan

The conclusion of the IRP is that an economic selection in 2019 of a 2:1 natural gas combined cycle (NGCC) resource is made in the base case analysis and all of the sensitivities considered, in support of an economic, reliable and responsible resource. More detail on the resource planning analysis methods and results are provided in Section 8 of this report.

1.1 THE WPL SYSTEM

WPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas in selective markets in southern and central Wisconsin. WPL serves more than 460,000 electric customers in 34 counties in Wisconsin and more than 180,000 natural gas customers in 21 counties in Wisconsin. In 2013, WPL's electric retail and wholesale customers' actual demand peaked at 2,603 MW resulting in a coincident peak obligation of 2,846 MW[1] based on Midcontinent Independent System Operator, Inc. (MISO) Module-E rules, which is the basis for all load data presented in this report.

Based on the load forecast used in this IRP, WPL expects the MISO-coincident peak demand obligation to grow from the 2013 level of 2,753 to 3,283 in 2042, a growth of 529 MW over the 30-year forecast horizon, reflecting an annual compounded and average annual growth rate of approximately 0.6 percent.

WPL's service distribution systems include over 31,000 miles of electric distribution line, 89 percent of which are rural, and over 4,300 miles of natural-gas distribution mains. WPL satisfies its forecasted requirements for load, MISO resource adequacy, and renewable portfolio standards with generation resources located in Wisconsin, Minnesota, and Iowa. These resources consist of both WPL-owned resources and purchase power agreements (PPAs). In 2014, WPL's owned units contributed approximately 2,487 MW_{UCAP} toward MISO resource adequacy requirements. Units operating under PPA agreements account for 311 MW[2]$_{UCAP}$. Together, in 2014 these units composing WPL's portfolio represent 2,798 MW_{UCAP}[3] towards WPL's resource adequacy.

WPL's portfolio includes base load and intermediate load resources, which operate year round and are fueled with coal and natural gas. Also included in the portfolio are wind, hydro, and simple cycle combustion turbine (CT) generators. Wind and hydro provide non-dispatchable energy while CT generators provide supplemental "peak" energy at times throughout the year when demand is highest.

[1] This IRP was developed using a November 2013 forecast which projected a 2013 peak of 2,512MW and a corresponding obligation of 2,753MW as indicated in Table 6.1.1.
[2] The 311 MW_{UCAP} includes Sheboygan Falls simple cycle ct, Castle Rock hydro, Pentenwell hydro, Forward Energy wind, Monfort wind, and Top of Iowa wind.
[3] The acronym "UCAP" is a MISO term that means "Unforced Capacity" and represents the capacity that can be registered with MISO in the annual capacity auction.

Recent, planned, and proposed changes to the WPL generation fleet include:

- Recent purchase of the natural gas combined cycle Riverside Energy Center facility from Riverside Energy Center LLC (sale completed, December 2012);
- Recent installations of Air Quality Control Systems including:
    - Columbia Energy Center Units 1 and 2 scrubber and baghouse (in service 2014);
    - Columbia Energy Center Unit 2 Selective Catalytic Reduction system (expected in service date of 2018);
    - Edgewater Generation Station Unit 5 Selective Catalytic Reduction system (in service December 2012);
    - Edgewater Generation Station Unit 5 scrubber and bag-house (in service June 2016)
- Planned retirements of Edgewater Generation Station Unit 3 and Nelson Dewey Generating Station Units 1 and 2 (by the end of 2015);
- Planned retirement of Edgewater Generation Station Unit 4 (by the end of 2018);
- Planned retirement of Rock River and Sheepskin gas-fired simple cycle combustion turbines at the end of 2019 ; and
- Proposed 2:1 natural gas combined cycle facility (expected in service by early 2019).

Each of these points is briefly explained in the following sections.

Recent Purchase of Riverside Energy Center

Riverside Energy Center's contribution to WPL's portfolio capacity is 545 MW_{UCAP} beginning in 2014.

Recent installations of Air Quality Control Systems

WPL and its partners of the Columbia Energy Center have successfully added a scrubber and baghouse to Columbia Energy Center Units 1 and 2, and expect to bring a Selective Catalytic Reduction system online in 2018 for Unit 2. The scrubber and baghouse was added to comply with SO2 reduction requirements, pending and future. This addition is expected to reduce SO2 emissions from Columbia Units 1 and 2 by 82 and 89 percent, respectively. The Selective Catalytic Reduction (SCR) system at the Columbia Energy Center is being added to reduce NOx emissions to promote compliance with current and anticipated rules and to comply with the consent decree in

Civil Action Nos. 13-cv-266 and 13-cv-265. This Columbia SCR is expected to reduce Unit 2 NOx emissions by over 50 percent.

The Company also completed the addition of a SCR system on the Edgewater Generation Station Unit 5 in 2012. This emission mitigation control was also installed to ensure compliance with applicable Reasonably Available Control Technology (RACT) requirements for NOx, as required by NR 428, Wis. Adm. Code. The Edgewater Generation Station Unit 5 SCR has shown, based on monthly data from January 2011 onward, the NOx emission rates have decreased by approximately 70 percent.

Planned Retirements

As partial compliance with the Consent Decree in Civil Action Nos. 13-cv-266 and 13-cv-265, WPL was ordered to retire, refuel, or repower Edgewater Generation Station Unit 3 and Nelson Dewey Generating Station Units 1 and 2 by the end of 2015. WPL announced in July 2012 that it would retire these units. This decision results in a loss of 270 MW_{UCAP} capacity. The Consent Decree also required that Edgewater Generation Station Unit 4 be retired, refueled, or repowered by the end of 2018. Upon regulatory approval of a new 2:1 NGCC to be installed and operational by 2019, WPL plans to retire this unit. As a result of the foregoing actions, WPL expects a net reduction in its generation capacity resources of 470 MW_{UCAP} by the end of 2018 compared to 2013.

Due to the inherent life-cycle risk with older combustion turbine (CT) units like Sheepskin, Rock River 3, 4, 5 and 6, this analysis also assumes the retirement of these units by mid-2020. WPL will, however, maintain flexibility with the retirement of these units through continued evaluation of MISO resource adequacy requirements, unit condition, and market conditions. These CT retirements contribute to an additional net reduction in WPL's generation capacity resources of 170 MW_{UCAP} by the end of 2019.

Proposed 2:1 NGCC Resource

The conclusion of this IRP is that an economic selection in 2019 of a 2:1 natural gas combined cycle (NGCC) resource is made in the base case analysis and all of the sensitivities considered.

With the foregoing realized and anticipated revisions to its generation portfolio, WPL expects to continue to deliver the reliable, low cost energy and exceptional service that its customers and communities count on – safely, efficiently, and responsibly.

1.2 Overview of Plan Development

The process used in developing this plan began with the system load forecast. This forecast includes the needs of all firm WPL customers. WPL's firm load forecast at the time of MISO's summer peak, plus a reserve requirement, is matched against existing capacity to determine WPL's annual resource needs. By using the EGEAS computer model, all combinations of existing resources are modeled with future resource alternatives to determine the optimal, least-cost expansion plan. The least-cost expansion plans for each case were determined by the dynamic programming model using the present value of revenue requirements option. In the output report, the first and last plan printed is plan 1 which is automatically ranked as the lowest cost plan by the dynamic programming module. Renewable alternatives, Demand-Side Management (DSM) programs and conventional supply-side units are all considered in this resource planning process. The objective function within EGEAS is to minimize the cumulative present value of revenue requirements (PVRR) for the 30-year planning period plus a 35-year extension period, while maintaining the MISO coincident peak planning reserve margin (PRM_{ucap}) of 7.3 percent in each year. The ultimate goal is to minimize cost while maintaining system reliability. The baseline set of planning assumptions are used to develop a base case, or reference case.

Once a reference case was determined, WPL developed additional scenarios and sensitivities by changing various input assumptions. These sensitivities are based on testing variations in modeling assumptions above and below the forecasted levels to provide supplemental insight into what might cause the model to choose a resource expansion plan that varies from the base case expansion plan. WPL creates sensitivities by varying key assumptions to provide supplemental insight. Examples of sensitivities include changes to:

- Load forecast;
- Market capacity and economy energy availability;
- Fuel costs;
- Capital costs;
- Tax credits for renewable resources; and

- Carbon regulation.

As a result of these analyses, WPL draws general conclusions about the least-cost expansion plan. These conclusions are considered to be general in nature because the units evaluated in the analysis are generic. In this case, WPL found in the analysis of generic units that a two-on-one (2:1) gas-fired combined cycle generation plant brought into service in 2019 was part of the least-cost expansion plan.

1.3 FUTURE INDUSTRY CONSIDERATIONS

WPL believes that it is important to consider potential future changes affecting the electric utility industry before making resource decisions, such as those reflected in this IRP. Currently, one of the biggest issues affecting resource planning is the uncertainty surrounding the likelihood and makeup of potential greenhouse gas regulation. WPL addressed this issue by modeling in EGEAS a carbon regulation scenario as one of the sensitivities, and by modeling two different renewables tax incentive scenarios. Detail on these scenarios, as well as the other modeling sensitivities, are provided in Section 8.5.2. Projected annual CO_2 emissions are provided in Section 8.7.

1.4 ANTICIPATED FILINGS WITH IRP

WPL is using this 2014 IRP in partial support of its application for a Certificate of Public Convenience and Necessity (CPCN) to construct a natural gas-fired combined-cycle generation resource of approximately 650MW (the Riverside Expansion) and for compliance with the expected data requests from the Public Service Commission of Wisconsin Staff for the 2016 Strategic Energy Assessment (SEA).

With regards to the CPCN, this IRP is the first step of a phased approach to the selection of the generating facility that will be proposed in the CPCN application. The first phase explores a variety of generically priced and specified planning alternatives to arrive at general conclusions about what resource should be pursued to satisfy the need for generation in 2019 and beyond.

2 LOAD FORECAST

The WPL base load forecast is used as the forecast in the EGEAS base case (or reference case). The elements of the WPL load forecast are described in the following subsections:

- Section 2.1 – Base Forecast;
- Section 2.2 – WPL Energy Forecasts;
- Section 2.3 – WPL Demand Forecast;
- Section 2.4 – Sensitivity and Scenarios; and
- Section 2.5 – Discussion of Demand Side Management (DSM).

The load forecast has two main components: the energy forecast and the demand forecast. The assumptions and methodologies for calculating the energy and demand forecasts are included in sections 2.2 and 2.3, respectively. To illustrate the sensitivity of the expansion plan to changes in the load forecast, high and low load forecast sensitivities were evaluated, and are described in Section 2.4. Section 2.5 discusses how demand side resources are handled within the load forecast.

2.1 BASE FORECAST

Table 2.1.1 summarizes WPL's annual energy and internal peak demand forecast in the base forecast, which exclude the forecasted energy and peaks associated with Wisconsin Public Power, Inc. (WPPI) and Great Lakes Utilities GLU[4] WPL uses the name "MISO ALTE" when referring to these annual energy and peak amounts. The adjustments made to the Internal Peak Demand forecast to arrive at the capacity obligations for the EGEAS analysis are found in Section 6.

[4] WPPI and GLU are entered into the EGEAS model as separate inputs. For ease of communication and consistency between internal stakeholders, their energy and demand forecasts are excluded from the base forecast amounts shown in Tables 2,1,1, 2.4.1.1, 2.4.1.2, 2.4.2.1, 2.4.2.2. Furthermore, WPPI and GLU represent fixed contractual requirements, and were therefore not subjected to the same scenario modelling applied to the MISO ALTE loads.

Table 2.1.1 - WPL Base Forecast: Energy and Internal Peak Demand[5]

Year	Energy (GWH)	Internal Peak Demand (MW)
2013[6]	12,553	2,603.
2014	12,632	2,547.8
2015	12,808	2,585.4
2016	13,008	2,618.9
2017	13,085	2,634.3
2018	13,184	2,654.1
2019	13,274	2,672.1
2020	13,372	2,691.9
2021	13,472	2,711.9
2022	13,571	2,732.1
2023	13,672	2,752.2
2024	13,774	2,772.5
2025	13,876	2,792.9
2026	13,979	2,813.5
2027	14,082	2,834.2
2028	14,187	2,855.1
2029	14,292	2,876.1
2030	14,398	2,897.3
2031	14,505	2,918.7
2032	14,612	2,940.2
2033	14,721	2,961.8
2034	14,830	2,983.7
2035	14,940	3,005.6
2036	15,051	3,027.8
2037	15,162	3,050.1
2038	15,274	3,072.5
2039	15,388	3,095.2
2040	15,502	3,118.0
2041	15,617	3,140.9
2042	15,732	3,164.1

Table 2.1.2 summarizes the forecasts WPL used for WPPI and GLU. The forecast assumes that WPL's contract with WPPI expires after May 2017.

[5] Excludes forecasted annual energy and peak demand amounts for WPPI or GLU

[6] The 2013 energy value shown consists of 8 months of weather-normalized actual sales and 4 months of forecasted sales. The 2013 peak value is the MISO-ALTE system peak during hour ending 1600 on July 18, 2013. The weather conditions during this hour were warmer than normal peaking conditions.

Table 2.1.2

WPPI and GLU Forecast: Energy and Internal Peak Demand

	WPPI		GLU	
Year	GWH	MW	GWH	MW
2013	[redacted]			
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			
2029	[redacted]			
2030	[redacted]			
2031	[redacted]			
2032	[redacted]			
2033	[redacted]			
2034	[redacted]			
2035	[redacted]			
2036	[redacted]			
2037	[redacted]			
2038	[redacted]			
2039	[redacted]			
2040	[redacted]			
2041	[redacted]			
2042	[redacted]			

2.2 WPL Energy Forecast

2.2.1 Methods

WPL's energy forecast is derived from the following key components:

- Class-specific electric meter forecasts[7];
- Class-specific use-per-meter regression models;
- Individually forecasted energy amounts of a select group of large industrial customers; and
- A wholesale customer forecast and a set of adjustments for external factors.

The WPL residential, commercial and industrial electric meter forecasts are derived using recent historical growth trends of meter counts.

The WPL residential, commercial and industrial use-per-meter forecasts are derived using monthly regression models. The monthly regression models are based on ten years of historical data and use several variables, for example heating degree days and cooling degree days, to explain variability in electricity usage.

Forecasted meter counts are multiplied by the monthly use-per-meter regression model output to forecast monthly energy sales for the residential, commercial and industrial customer classes.

Manual adjustments may be made to the forecast to account for external factors, such as the addition of a new large customer that may not have been accounted for in the historical sales data. These modeled amounts are added to the individual monthly forecasts for a select group of large industrial customers to arrive at WPL's retail customer forecast.

Wholesale forecasts are then added to the retail forecast to produce the total sales forecast.

Factors from the company's historical line loss study(s) are used to calculate transmission and distribution losses which are added to create the total energy forecast.

The methodology listed above results in a forecast of total monthly energy through 2020. The rate of forecasted energy growth from 2019 to 2020 is used to derive the long term forecast through 2042.

[7] The WPL electric meter forecast represents the forecasted number of meters per customer class

2.2.2 Data

Sources of information for key factors used in this process include:

- WPL uses 10 years of monthly sales and meter counts from WPL's billing system as the basis for its forecast models.
- Weather is measured using Heating Degree Days (HDD) and Cooling Degree Days (CDD) and matched to monthly sales amounts. Normal is defined as the 20-year rolling average using the average of the daily high and low temperature with a base of 65 degrees. Weather is reported from the Madison Airport.
- Historical economic data used in the use per meter regression models comes from a third party vendor, IHS Global Insight, unless otherwise stated. IHS Global Insights provides economic forecasts, which are used to forecast future sales.
- WPL uses information provided by its key account managers (KAMs), along with individual historical load data, to forecast sales for selected large customers.

2.3 WPL Demand Forecast

2.3.1 Definitions

Internal Peak Demand is defined as the highest observed load. For forecasting purposes, WPL adds any interruptions to the Internal Peak Demand, to calculate the Theoretical Demand.

2.3.2 Method

To forecast demand, WPL uses Theoretical Demand, the highest observed load plus the estimated interrupted load called during the peak time. Next, WPL reduces historical system load data by the load attributed to the large customers which are forecasted individually. The remaining load is forecasted using a consensus of three different regression models. The three models represent annual peak, monthly peaks, and summer seasons. The annual and summer seasonal models are averaged to arrive at an annual peak forecast. The annual forecast is then calendarized based on the monthly model. The individually forecasted customer peaks are added to the modeled results to arrive at the demand forecast. Finally the demand forecast is compared with the corresponding energy model for reasonability. The long term peak forecast assumes the growth rates of the long term energy forecast.

2.3.3 Data

All three regression models use:

- Ten years of peak demand and weather data;
- Theoretical Demand less large customer demand (Large Customer demand is forecasted independently from the regression models); and
- Personal Income from IHS Global Insight.

Individual models use, respectively:

- Annual model uses:
  - highest observation of load per year; and
  - high temperature on the peak day.
- Monthly model uses:
  - highest observation of load per month; and

  - heating degree days and cooling degree days.

- Seasonal model uses:
  - weekdays and non-holidays in June through September; and
  - peak day high temperature, prior day temperature, overnight low, and the dew point.

2.4 Load Forecast Analysis

Variation of the WPL load forecast is analyzed using a confidence interval analysis, and a high and low growth rate sensitivity. The confidence interval is based on regression analysis of data within the load forecast model while the high and low sensitivity are intended to account for factors external to the model. Over the course of the IRP study period, the high and low load growth sensitivities provide a wider band around the base forecast. The expansion planning analysis for the WPL 2014 IRP makes use of the high and low forecast for the high and low load growth sensitivities.

2.4.1 Load Forecast Confidence Interval Analysis

To estimate the statistical precision of the load forecast, WPL constructed annualized confidence intervals for the energy and demand forecasts.

2.4.1.1 Energy Confidence Interval

The confidence interval for the energy forecast utilizes a rolling 12-month annual error. The forecast error was determined using the 95% critical value on the standard deviation of the rolling annual errors. The confidence interval is presented below in Table 2.4.1.1. While the large industrial, wholesale, and small classes, like lighting, municipal pumping, and interdepartmental, are not statistically modeled, WPL applies the confidence interval as a percentage to the annual sales.

Table 2.4.1.1 - 95% Confidence Intervals (CI) - WPL Energy Models (GWH)[8]

Year	Energy Lower 95% CI (GWH)	Base Energy (GWH)	Energy Upper 95% CI (GWH)
2013[9]	12,553	12,553	12,553
2014	12,325	12,632	12,939
2015	12,496	12,808	13,121
2016	12,689	13,008	13,326
2017	12,765	13,085	13,405
2018	12,862	13,184	13,506
2019	12,950	13,274	13,598
2020	13,046	13,372	13,699
2021	13,143	13,472	13,800
2022	13,241	13,571	13,902
2023	13,339	13,672	14,005
2024	13,438	13,774	14,109
2025	13,538	13,876	14,213
2026	13,639	13,979	14,319
2027	13,740	14,082	14,425
2028	13,843	14,187	14,531
2029	13,945	14,292	14,639
2030	14,049	14,398	14,747
2031	14,154	14,505	14,856
2032	14,259	14,612	14,966
2033	14,365	14,721	15,077
2034	14,471	14,830	15,188
2035	14,579	14,940	15,301
2036	14,687	15,051	15,414
2037	14,796	15,162	15,528
2038	14,906	15,274	15,643
2039	15,017	15,388	15,758
2040	15,129	15,502	15,875
2041	15,241	15,617	15,992
2042	15,354	15,732	16,110

[8] Excludes forecasted annual energy amounts for WPPI or GLU

[9] The 2013 energy value shown consists of 8 months of weather-normalized actual sales and 4 months of forecasted sales.

2.4.1.2 Demand Confidence Interval

The confidence interval for the demand forecast is developed using the seasonal model which contains the greatest number of peak observations. To illustrate the forecast range stemming from historical variation from the model, the 95% confidence interval for the demand forecast is listed below in Table 2.4.1.2.

Table 2.4.1.2 - 95% Confidence Interval - Internal Peak Demand (MW)[10]

Year	Peak Lower 95%CI (MW)	Base Peak (MW)	Peak Upper 95% CI (MW)
2013[11]	2,603	2,603	2,603
2014	2,397.2	2,547.8	2,698.3
2015	2,432.6	2,585.4	2,738.2
2016	2,464.1	2,618.9	2,773.7
2017	2,478.6	2,634.3	2,789.9
2018	2,497.2	2,654.1	2,810.9
2019	2,514.2	2,672.1	2,830.0
2020	2,532.8	2,691.9	2,851.0
2021	2,551.6	2,711.9	2,872.2
2022	2,570.6	2,732.1	2,893.5
2023	2,589.6	2,752.2	2,914.8
2024	2,608.6	2,772.5	2,936.3
2025	2,627.9	2,792.9	2,957.9
2026	2,647.2	2,813.5	2,979.7
2027	2,666.7	2,834.2	3,001.7
2028	2,686.4	2,855.1	3,023.8
2029	2,706.2	2,876.1	3,046.1
2030	2,726.1	2,897.3	3,068.5
2031	2,746.2	2,918.7	3,091.1
2032	2,766.4	2,940.2	3,113.9
2033	2,786.8	2,961.8	3,136.9
2034	2,807.3	2,983.7	3,160.0
2035	2,828.0	3,005.6	3,183.2
2036	2,848.9	3,027.8	3,206.7
2037	2,869.8	3,050.1	3,230.3
2038	2,891.0	3,072.5	3,254.1
2039	2,912.3	3,095.2	3,278.1
2040	2,933.7	3,118.0	3,302.2

[10] Excludes forecasted annual peak demand amounts for WPPI or GLU

[11] The 2013 peak is the actual MISO-ALTE system peak that occurred during HE 1600 hours on July 18, 2013. Weather conditions during this hour were warmer than normal peaking conditions.

2041	2,955.3	3,140.9	3,326.5
2042	2,977.1	3,164.1	3,351.0

2.4.2 Growth Rate Sensitivities

To indicate the sensitivity of the resource plan to higher or lower than planned growth, WPL estimated a high and low load forecast as noted in Tables 2.4.2.1 and 2.4.2.2. To estimate the loads for these scenarios, WPL increased or decreased the expected growth rate of the base forecast by 50 basis points. WPL recognizes that load could vary due to several variables, such as changes in regional economics, wholesale contracts, distributed generation installations, conservation actions, or changes in electric prices.

WPL's customers primarily participate in DSM conservation activities through the Focus on Energy program. WPL does not use DSM as a separate input to its forecast.[12] Conservation savings achieved through Focus on Energy and other programs are included in sales history and are, therefore, reflected in the base forecast. The low and high load and energy scenario results presented in Table 2.4.2.1 and Table 2.4.2.2, respectively, include potential incremental additions and subtractions to current DSM savings.

[12] Section 3 provides more detail on the evaluation of DSM

Table 2.4.2.1 - Load Growth Sensitivities - Energy (GWH)[13]

Year	Low (GWH)	Base (GWH)	High (GWH)
2013[14]	12,553	12,553	12,553
2014	12,632	12,632	12,632
2015	12,745	12,808	12,871
2016	12,880	13,008	13,136
2017	12,892	13,085	13,280
2018	12,925	13,184	13,447
2019	12,949	13,274	13,606
2020	12,980	13,372	13,775
2021	13,011	13,472	13,946
2022	13,043	13,571	14,119
2023	13,074	13,672	14,294
2024	13,106	13,774	14,472
2025	13,138	13,876	14,652
2026	13,169	13,979	14,833
2027	13,201	14,082	15,018
2028	13,233	14,187	15,204
2029	13,265	14,292	15,393
2030	13,297	14,398	15,584
2031	13,329	14,505	15,778
2032	13,361	14,612	15,973
2033	13,394	14,721	16,172
2034	13,426	14,830	16,372
2035	13,458	14,940	16,576
2036	13,491	15,051	16,781
2037	13,523	15,162	16,990
2038	13,556	15,274	17,201
2039	13,589	15,388	17,414
2040	13,621	15,502	17,630
2041	13,654	15,617	17,849
2042	13,687	15,732	18,070

[13] Excludes forecasted annual energy amounts for WPPI or GLU

[14] The 2013 peak is the actual MISO-ALTE system peak that occurred during HE 1600 hours on July 18, 2013. Weather conditions during this hour were warmer than normal peaking conditions.

Table 2.4.2.2

Load Growth Sensitivities - Peak (MW)

Year	Low (MW)	Base (MW)	High (MW)
2014	2,547.8	2,547.8	2,547.8
2015	2,571.9	2,585.4	2,598.8
2016	2,591.8	2,618.9	2,646.1
2017	2,594.5	2,634.3	2,674.5
2018	2,600.8	2,654.1	2,708.1
2019	2,605.4	2,672.1	2,740.2
2020	2,611.5	2,691.9	2,774.3
2021	2,617.7	2,711.9	2,808.9
2022	2,624.0	2,732.1	2,843.9
2023	2,630.1	2,752.2	2,879.2
2024	2,636.3	2,772.5	2,915.0
2025	2,642.3	2,792.9	2,951.1
2026	2,648.5	2,813.5	2,987.8
2027	2,654.6	2,834.2	3,024.8
2028	2,660.8	2,855.1	3,062.3
2029	2,667.0	2,876.1	3,100.3
2030	2,673.2	2,897.3	3,138.8
2031	2,679.5	2,918.7	3,177.8
2032	2,685.7	2,940.2	3,217.1
2033	2,691.9	2,961.8	3,257.0
2034	2,698.2	2,983.7	3,297.5
2035	2,704.4	3,005.6	3,338.2
2036	2,710.8	3,027.8	3,379.7
2037	2,717.1	3,050.1	3,421.6
2038	2,723.4	3,072.5	3,464.0
2039	2,729.7	3,095.2	3,506.9
2040	2,736.1	3,118.0	3,550.4
2041	2,742.4	3,140.9	3,594.3
2042	2,748.8	3,164.1	3,638.9
Excludes forecasted annual peak demand amounts for WPPI or GLU			

3 DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

3.1 GENERAL APPROACH

This section presents the modeling of WPL's energy efficiency from recent levels to levels in the Public Service Commission of Wisconsin (PSCW) **Quadrennial Planning Process II** Docket 5-FE-100, PSC REF#:215245[15].

The basis for the energy and demand potential estimates derived in this section are based on the energy efficiency efforts found in the **Strategic Energy Assessment - Energy 2018**, PSC REF#: 176432[16]. The Aggressive DSM model assumes the spending levels and goals stated in the Quadrennial Planning Process II.

2005 Wisconsin Act 141, enacted March 17, 2006, includes utility energy efficiency provisions, which generally took effect July 1, 2007. These provisions affect the dollar allocation and the dollar amount of Wisconsin utilities' energy efficiency and conservation budgets for the Statewide Energy Conservation Program (currently known as Wisconsin Focus on Energy). Beginning July 1, 2007, the Statewide Energy Conservation Program was fully funded at the level of 1.2 percent of utility electric and natural gas revenues. Act 141 also allows for the PSCW to change the energy efficiency savings goals, levels and spending for the Focus on Energy programs with approval by the Joint Committee on Finance.

The PSCW's Quadrennial Planning Docket 5-FE-100 Order (ERF REF#: 215245), signed on September 3rd, 2014, set the energy efficiency levels for 2015 through 2018. Table 3.1.1 shows the statewide historic 2012 and 2013 actual electric savings, estimated 2014 electric savings and spending results, and the projected spending and electric savings levels from 2015 through 2018, as outlined in the PSCW's Quadrennial Planning Docket 5-FE-100. This docket is used as the basis for the WPL Aggressive DSM model.

[15] http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=215245
[16] http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=176432

Table 3.1.1 Actual and Projected Electric Savings and Spending Levels

Year	Electric Goal: Net as % retail load under Quadrennial Plan	Spending Statewide in Quadrennial Plan
2012	0.67%[17]	1.2%
2013	0.90%[18]	1.2%
2014	0.90% [19]	1.2%
2015	0.77% [20]	1.2%
2016	0.77% [21]	1.2%
2017	0.77% [21]	1.2%
2018	0.77%[21]	1.2%
2019*	0.77%	1.2%
2020*	0.77%	1.2%

(* Next Quadrennial Planning 2019 – 2022 estimate)

3.2 Current Program Review

WPL has substantial experience in participating in, or managing, energy efficiency programs. WPL contributes to the statewide programs in addition to operating a voluntary utility-run program. The statewide programs are those within Focus on Energy, while the utility voluntary program is managed by WPL.

WPL also operates a load management programs for its customers. Industrial customers utilize Commercial and Industrial (C&I) Interruptible rates to help manage load. This program is applicable to customers on the WPL Industrial Power Time-of-Day rates. Customers taking service under these rates have an on-peak interruptible demand of 200 kW or greater, and are eligible to participate in the company's one-hour-notice or instantaneous Interruptible Rider. Participants in the program agree that either within one hour, or immediately upon receiving notice, to reduce load by an amount equivalent to the Contracted Interruptible Demand or reduce load to a level less than, or equal to, the Contracted Firm Demand. Participation in C&I interruptible rates has been stable and will likely stay near current levels in the future.

WPL provides the interruptible customer with an electronic notification to curtail. The customer is responsible for all equipment and process changes to meet load reduction. Customers sign a

[17] Actual
[18] Actual
[19] Estimated
[20] Projected

contract for a fixed term of three years. They are divided into groups so that WPL has the ability to interrupt a subset of the interruptible customers at the time of an interruption. WPL will equally distribute the number of interruptions and the total number of hours among the groups to the greatest extent possible.

3.3 Aggressive DSM Alternative

Given WPL's long history of providing conservation programs to its customers, DSM impacts from past program results are embedded in the peak load and energy forecasts. With the conclusion of the WPL Shared Savings program in December 2013, WPL will continue to provide educational, training and outreach programs for energy efficiency and conservation for its Commercial and Industrial customers. This includes participating in pilot initiatives with Focus on Energy implementers and continued efforts to increase Focus on Energy participation. WPL will also consider other pilot initiatives with PSCW staff approval. The forecast DSM represents the average percentage of Focus on Energy activity in the WPL territory for EGEAS.

Quadrennial Plan estimates are the best data WPL has to estimate aggressive DSM until actual programs are designed and set by the program administrator. WPL is using the Quadrennial Plan levels and numbers for Aggressive DSM, but delaying the implementation by 2 years in the model to reflect realistic time for funding increases and program ramp up to achieve results in 2016. The aggressive DSM model illustrates program spending requirements to achieve comparable energy efficiency programs in Iowa and Minnesota. For WPL, the net between existing Wisconsin vs. proposed Iowa and Minnesota helps illustrate the incremental costs and MWh necessary to equal Iowa and Minnesota.

Table 3.3.1 below shows the annual increase over embedded historic DSM levels which are modeled for the aggressive DSM alternative. For IRP modeling, Aggressive DSM incremental spending begins in 2014; The incremental energy savings begin in 2016 after a two year ramp-up.

Table 3.3.1 Annual Increases of Aggressive DSM

Year in Model	PSCW Net Goal as % Retail Load	Annual Incremental MWh Additional for PSCW Goal Net {at Generator}	Energy MWh Avoided Aggressive DSM {at Generator}	Annual Incremental MW based on Load factor {at Generator}	Estimated Spending for Incremental DSM
2016	0.77%	41,269	41,269	7.3	$15,674,864
2017	0.77%	41,269	82,537	14.6	$15,988,362
2018	0.77%	41,269	123,806	21.9	$16,308,129
2019*	0.77%	41,269	165,075	29.2	$16,634,291
2020*	0.77%	41,269	206,343	36.5	$16,966,977

(* - Quadrennial Planning 2019 – 2022 estimate)

Funding for the Quadrennial Planning Process II is 1.2% of operating revenue beginning in 2015. The net MWh savings state wide is 0.77% of retail load (See Table 3.1.1) The WPL Aggressive DSM unit included in the 2014 IRP could achieve an additional incremental savings of approximately 41,269 MWH. The additional cost to achieve these savings annually is shown in Table 3.3.1.

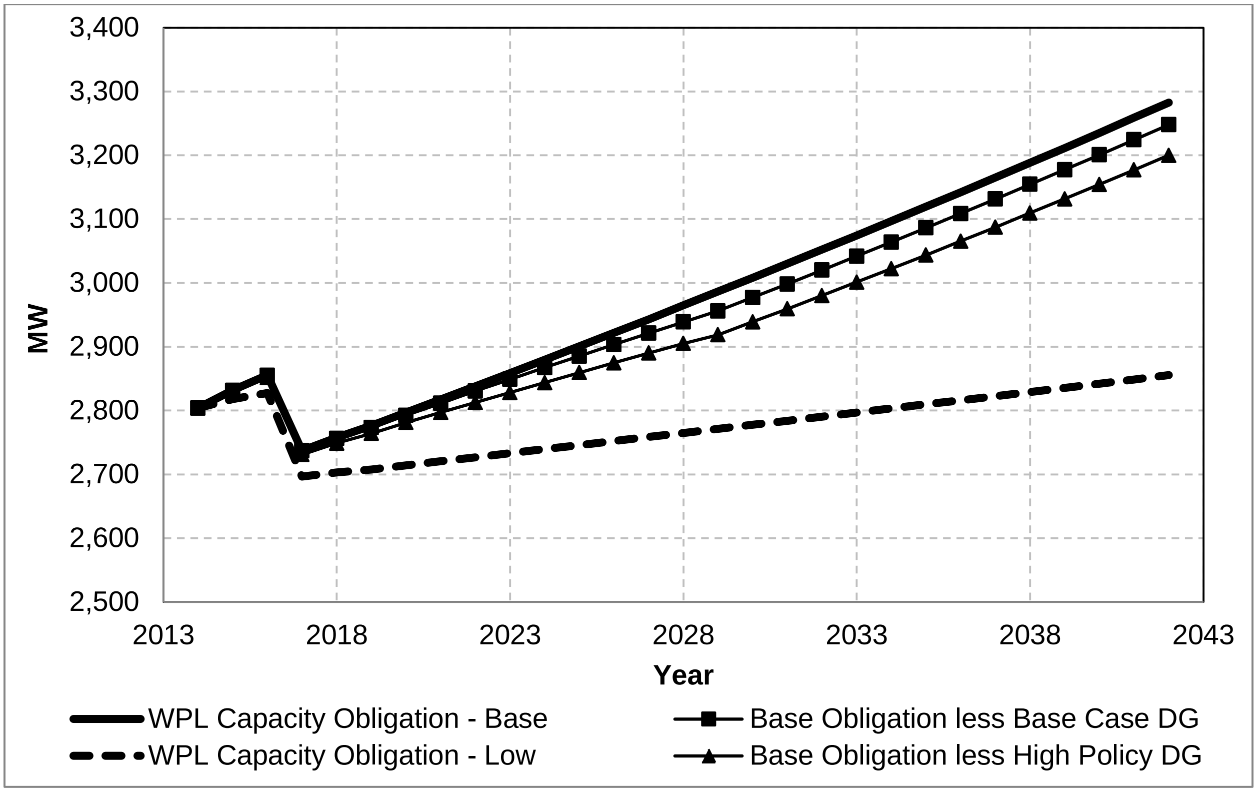
Tables 3.3.2 and 3.3.3 presented in Appendix 3A show the development of the data used to represent the hypothetical aggressive DSM program modeled as a supply-side resource in the EGEAS model.

4 DISTRIBUTED GENERATION

As identified in section 2.4.2, WPL developed a low load forecast due to recognition that load could vary due to, among other things, distributed generation installations. In order to better understand the potential variation that could result from distributed generation installations, WPL hired Tetra Tech to perform an independent study of this potential in WPL's service territory. This study is provided in confidential Appendix 4A. An addendum to the report is provided in Appendix 4B. The resulting aggregate DG forecast is shown in Appendix 4C.

The results of the study show that load forecast variation attributable to DG falls within the difference between the base and low load forecast. This is evident in Table 4.1.1 which shows an aggregate summer peak impact from DG of approximately 34MW over the course of the 30 year study period, which is less than 10% of the peak load impact identified in the low load growth sensitivity which identified 415MW of peak load variation from the base forecast by the end of the study period. Therefore, a separate sensitivity is not necessary because the analysis of the low load forecast encompasses the variation that could be realized from DG.

Table 4.1.1 – WPL 2014 IRP – Potential DG Impact on Capacity Obligation



5 EXISTING WPL GENERATING RESOURCES

This section summarizes WPL's existing generating fleet as of 2013, the first year of the study period in the EGEAS analysis. WPL evaluated the ability of these resources to serve its anticipated future energy needs and meet the MISO planning reserve margin (PRM) requirement for capacity. Section 5.1 provides an overview of WPL's existing generating resources, both owned and purchased. Section 5.2 identifies changes that have occurred in the WPL generating resource fleet between WPL's 2012 IRP[21] and the current WPL 2014 IRP. Additional projection information about the existing resources is included in Section 6 as part of a calendar table showing modifications to existing resources.

5.1 GENERATING RESOURCES

WPL has a mix of both owned and contracted supply-side resources to meet customer demands in a reliable and cost effective manner. The existing supply-side and demand-side resources are presented in Tables 5.1.1 (below) and 5.1.2 (in Appendix 5A) as they are specified in WPL's 2014 IRP EGEAS model. Summer reserve capacities (zonal resource credits, ZRCs) are expressed at 2013 values. Some PPAs do not begin providing service until after the base year. These units appear in the load and capability presentation in Section 6 of this IRP report.

Table 5.1.1 presents the key model input data regarding performance and operating cost of each resource. Included in this table are the following:

- The common unit names;
- The abbreviated unit names as they appear in the EGEAS model;
- Unit summer reserve capacities;
- Fuel type or motive force for units that do not burn fuel;
- Unit ownership;
- Full load heat rates;
- Fuel costs; and
- Variable operations and maintenance costs.

[21] The 2012 IRP was used by WPL to support its EGEAS analysis for the application for a certificate to construct the scrubber and baghouse for Edgewater Unit 5 (Docket No. 6680-CE-174) and to respond to the PSCW staff data requests in 2013 for the Strategic Energy Assessment report for 2014 (Docket No. 5 ES-107).

It should be noted that Table 5.1.1 includes a demand-side resource representing WPL's interruptible load. This is included as a supply-side resource to satisfy MISO requirements as described in section 6.3 of this report.

Information about the emission control systems is presented in Table 5.1.2 of Appendix 5A. Systems included in this appendix were installed on the Riverside Energy Center and the coal-fired units as of December 31, 2014. Appendix 5A also presents major comprehensive asset management programs (CAMP) completed by December 31, 2014.

Table 5.1.3 in Appendix 5B provides greater detail for existing units. This detail includes cost, cost escalation, full-load heat rates, capacities, emission rates, and emission rate multipliers. Data for generating units are presented in the order they appear in the EGEAS model.

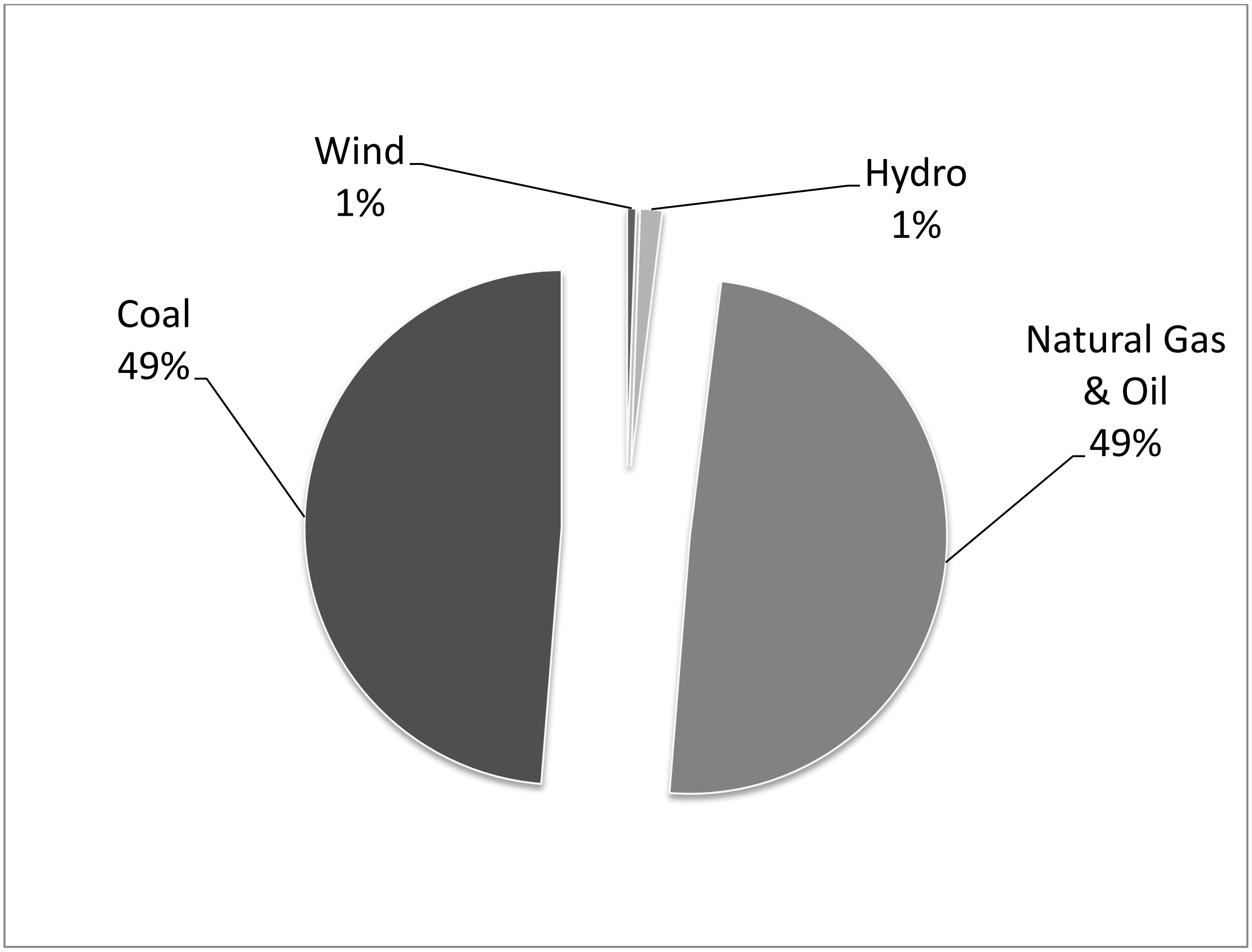
Table 5.1.1 WPL's Existing Supply-Side Resources - Confidential

Resource in Order of Appearance in EGEAS (Non-Energy Only Resources)	EGEAS Unit Name	2013 Summer Reserve Capacity (ZRC)	Ownership*	Fuel or Motive Force for Noncombustible Resources	2013 Full Load Heat Rate (Btu/kWh)	Fuel Cost (2013$/M Btu)	Variable O&M Cost (2013$/M Wh)
Supply-Side Resources							
Top of Iowa 1 (Worth)	TOIA X	4.4	PPA	Wind	[redacted]		
Forward II	FENA X	3.4	PPA	Wind			
Cristal Lake 2**	CL1A X		PPA	Wind			
Monfort	EDNA X	0.4	PPA	Wind			
Petenwell Hydro	WRHY X	10.1	PPA	Hydro			
Castle Rock	WRHY X	8.8	PPA	Hydro			
Juneau/Petenwell CT	WRCT X	4.7	PPA	Fuel Oil			
Kilbourn	WPHY X	6.2	WPL	Hydro			
Prairie du Sac 1	WPHY X	14.1	WPL	Hydro			
Cedar Ridge	CEDR X	7.9	WPL	Wind			
Bent Tree**	BENT C		WPL	Wind			
Rock River 3	ROR3 X	23.3	WPL	Natural Gas			
Rock River 4	ROR4 X	13.6	WPL	Natural Gas			
Rock River 5	ROR5 X	47.9	WPL	Natural Gas			
Rock River 6***	ROR6 X		WPL	Natural Gas			
Sheepskin 1	SIN1 X	32.9	WPL	Natural Gas			
South Fond Du Lac 2	SFL2 X	71.6	WPL	Natural Gas & Oil			
South Fond Du Lac 3	SFL3 X	71.3	WPL	Natural Gas & Oil			
Sheboygan Falls 1	SBN1 X CT	140.3	Leased	Natural Gas			
Sheboygan Falls 2	SBN2 X CT	141.7	Leased	Natural Gas			
Neenah CT1	NEN1 X CT	134.7	WPL	Natural Gas			
Neenah CT2	NEN2 X CT	144.0	WPL	Natural Gas			
Riverside	RIV X	568.3	WPL	Natural Gas			
Edgewater 3	EDG3 X R15	54.3	WPL	Coal			
Edgewater 4	EDG4 X E4R18	210.5	WPL 68.2%	Coal			
Edgewater 5	EDG5 X E4R18	402.1	WPL	Coal			
Columbia Unit 1	COL1 X 3538	255.7	WPL 46.2%	Coal			
Columbia Unit 2	COL2 X 3538	248.4	WPL 46.2%	Coal			
Nelson Dewey 1	NED1 X R15	104.0	WPL	Coal			
Nelson Dewey 2	NED2 X R15	103.0	WPL	Coal			
Total Supply-Side ZRCs		2,827.6					
Demand Resources:							
Interruptible Load	DINT X	147.2					
Supply Purchases & Sales****		(105.0)					
Total ZRCs		**2,869.8**					
Energy Only Resources:							
Kewaunee PPA*****	KNPP C LY2013		PPA	Nuclear			
Morgan Stanley Power	MSCG C On Pk14		PPA	On-Peak			
Morgan Stanley Power	MSCG C Off Pk14		PPA	Off-Peak			
Morgan Stanley Power	MSCG C On Pk1518		PPA	On-Peak			
Morgan Stanley Power	MSCG C Off Pk1518		PPA	Off-Peak			
Northern States Power Co.	NSPR C RTC1415		PPA	Around the clock			
Economy Purchases RTC	ERTC		Economy	Around the clock			
Economy Purchases OPK	EOPK		Economy	Peaking			

* "PPA" means the resource is not owned by WPL and is acquired through a purchase power agreement (PPA).
WPL means a WPL-owned resource. The number following indicates WPL's ownership share of that unit.
**Crystal Lake & Bent Tree have zero capacities in PY 2013/14 reflecting provisional interconnection service awaiting transmission upgrades.
***Rock River Unit 6 has a zero capacity in PY 2013/14 because it was not returned to service in time for a GVTC after an equipment failure.
**** Modeled in EGEAS ORT as ZRC transfers.
***** PPA expired at the end of 2013, modeled in EGEAS as an energy-only resource in 2013.

Additionally, Figure 5.1.1 shows the relative zonal resource capacities by fuel type or motive force for noncombustible resources such as wind or hydroelectric power (hydro).

Figure 5.1.1 – 2013 Zonal Resource Capacity by Fuel Type



6 Load and Capability

6.1 Capacity Position

The primary purpose of the load and capability section is to define the capacity need established by the forecasted WPL capacity position. This is accomplished by first establishing the MISO capacity obligation, and then contrasting it with WPL's existing adjusted net resources. The capacity position in each year is the difference of the WPL adjusted net resources less the capacity obligation. A negative position means that WPL does not have enough capacity in its portfolio in that year in order to satisfy the capacity obligation to MISO.

6.1.1 Capacity Obligation

The capacity obligation represents the amount of capacity, in the form of MISO Zonal Resource Credits (ZRCs) required to satisfy the Planning Reserve Margin Requirement (PRMR) established in the MISO Tariff.[22] This obligation is calculated in the following steps for the annual MISO capacity accreditation process.

<u>WPL Peak Load Forecast</u>

WPL develops the peak retail demand forecast, as described in section 2 of this IRP. The forecast is identified in Table 6.1.1 as the "Non-Coincident Peak Supply."

<u>Peak Adjustment</u>

The WPL peak is not coincident with the MISO peak. Therefore, MISO requires the WPL peak to be adjusted so that it is coincident with the MISO peak. This non-coincident-to-coincident adjustment is referred to in Table 6.1.1 as the "Peak Adjustment."

<u>Wholesale Adjustment</u>

The adjusted peak forecast is then grossed down (reduced) by transmission losses in order to add in Full Responsibility Purchase (FRP) and Full Responsibility Sale (FRS) contracts. The annual net FRP and FRS capacity, listed as "contracts" in Table 6.1.1, is added to the grossed down peak. The resulting sum is grossed back up by transmission losses to the supply side, resulting in the Adjusted Net Peak.

[22] MISO Resource Adequacy Business Practice Manual, BPM-011-r12 (effective Aug. 1, 2013).

Planning Reserve Margin Requirement

MISO has a planning reserve margin requirement (PRMR) for capacity planning. The adjusted net peak is grossed up by the PRMR which results in the annual MISO capacity obligation. In EGEAS, the gross-up factors for transmission losses and PRMR are combined into one adjustment factor, as represented in the column titled "EGEAS PRM," in Table 6.1.1.

Table 6.1.1 – WPL 2014 IRP Capacity Obligation - Base Case

Year	Non-Coincident Peak Supply	Peak Adjustment Non-Coincident to Coincident	Transmission Loss Adjustment	Contracts	EGEAS PRM (includes trans losses 2.85% and MISO PRM 7.3%)	Obligation
Formula	Forecast	[redacted]	less	add	add	=
		[redacted]	2.870%		10.358%	
2013	2512.0	[redacted]	70.3	[redacted]	232.6	2753.2
2014	2547.8	[redacted]	70.2	[redacted]	263.2	2804.1
2015	2585.4	[redacted]	71.2	[redacted]	265.8	2831.8
2016	2618.9	[redacted]	72.1	[redacted]	268.0	2855.5
2017	2634.3	[redacted]	72.6	[redacted]	256.9	2737.5
2018	2654.1	[redacted]	73.1	[redacted]	258.9	2758.0
2019	2672.1	[redacted]	73.6	[redacted]	260.6	2776.5
2020	2691.9	[redacted]	74.1	[redacted]	262.5	2796.9
2021	2711.9	[redacted]	74.7	[redacted]	264.4	2817.4
2022	2732.1	[redacted]	75.3	[redacted]	266.4	2838.2
2023	2752.2	[redacted]	75.8	[redacted]	268.3	2858.9
2024	2772.5	[redacted]	76.4	[redacted]	270.3	2879.7
2025	2792.9	[redacted]	76.9	[redacted]	272.3	2900.8
2026	2813.5	[redacted]	77.5	[redacted]	274.2	2921.9
2027	2834.2	[redacted]	78.1	[redacted]	276.2	2943.1
2028	2855.1	[redacted]	78.6	[redacted]	278.3	2964.8
2029	2876.1	[redacted]	79.2	[redacted]	280.3	2986.4
2030	2897.3	[redacted]	79.8	[redacted]	282.3	3008.1
2031	2918.7	[redacted]	80.4	[redacted]	284.4	3030.1
2032	2940.2	[redacted]	81.0	[redacted]	286.5	3052.3
2033	2961.8	[redacted]	81.6	[redacted]	288.6	3074.5
2034	2983.7	[redacted]	82.2	[redacted]	290.7	3097.0
2035	3005.6	[redacted]	82.8	[redacted]	292.8	3119.5
2036	3027.8	[redacted]	83.4	[redacted]	294.9	3142.4
2037	3050.1	[redacted]	84.0	[redacted]	297.1	3165.4
2038	3072.5	[redacted]	84.6	[redacted]	299.3	3188.5
2039	3095.2	[redacted]	85.3	[redacted]	301.4	3211.6
2040	3118.0	[redacted]	85.9	[redacted]	303.6	3235.1
2041	3140.9	[redacted]	86.5	[redacted]	305.9	3258.8
2042	3164.1	[redacted]	87.2	[redacted]	308.1	3282.6

6.1.2 Adjusted Net Resources

The adjusted net resources represent the amount of WPL capacity that is eligible to register as a MISO Zonal Resource Credit (ZRC), and contribute to WPL's annual MISO capacity obligation. The WPL forecast of adjusted net resources is delineated into the following three categories for the annual MISO capacity accreditation process.

Supply Side Resources

All of the resources in WPL's portfolio which have the capability of generating electricity and registering with MISO as a capacity resource are classified as supply side resources. This includes owned and PPA sources of wind, hydro, coal, gas and oil units.

Demand Side Resources Classified as Supply

Demand side resources do not generate electricity. Rather they have the ability to affect peak demand through reductions in load. This resource category typically includes interruptible customers and direct load control programs. For reasons described in Section 6.3, these resources are classified as supply side resources in MISO for the annual capacity auction.

Capacity Purchases and Sales

WPL has several capacity purchases and sales that are identified in MISO as "ZRC Transfers." These are annual capacity transactions within MISO Zone 2 that increase or decrease WPL's capacity position.

6.1.3 Capacity Position

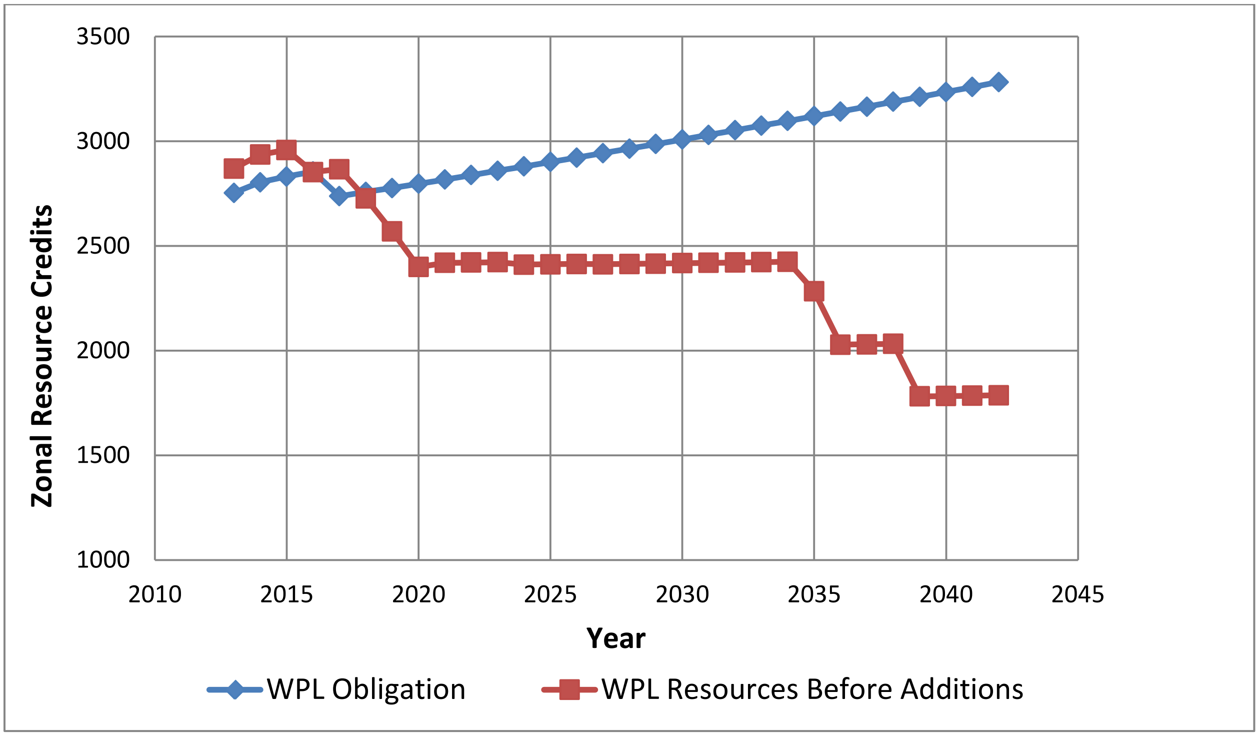
The capacity position in each year is the net of the WPL adjusted net resources less the capacity obligation, as represented in the column titled "WPL Position" in Table 6.1.2. A negative position means that WPL does not have enough capacity in its portfolio in that year in order to satisfy the capacity obligation to MISO.

Table 6.1.2 - WPL Capacity Position - Base Case (Before EGEAS Expansion Plan)

Year	Obligation (from Table 6.1.1)	Supply Side Resources	Demand Side Resources Classified as Supply	Capacity Purchases and Sales	Adjusted Net Resources	WPL Position Long (short)
Formula			[redacted]	add	=	
2013	2753.2	2827.6	[redacted]		2869.8	117
2014	2804.1	2797.6			2936.6	133
2015	2831.8	2817.6			2958.6	127
2016	2855.5	2555.2			2852.6	(3)
2017	2737.5	2567.6			2866.5	129
2018	2758.0	2577.7			2727.6	(30)
2019	2776.5	2418.1			2569.5	(207)
2020	2796.9	2246.6			2399.4	(398)
2021	2817.4	2265.0			2419.4	(398)
2022	2838.2	2265.0			2420.9	(417)
2023	2858.9	2265.0			2422.5	(436)
2024	2879.7	2251.9			2411.0	(469)
2025	2900.8	2251.9			2412.6	(488)
2026	2921.9	2251.9			2414.2	(508)
2027	2943.1	2248.6			2412.5	(531)
2028	2964.8	2248.6			2414.1	(551)
2029	2986.4	2248.6			2415.8	(571)
2030	3008.1	2248.6			2417.4	(591)
2031	3030.1	2248.6			2419.2	(611)
2032	3052.3	2248.6			2420.9	(631)
2033	3074.5	2248.6			2422.6	(652)
2034	3097.0	2248.6			2424.4	(673)
2035	3119.5	2106.1			2283.6	(836)
2036	3142.4	1849.1			2028.4	(1,114)
2037	3165.4	1849.1			2030.2	(1,135)
2038	3188.5	1849.1			2032.0	(1,157)
2039	3211.6	1596.4			1781.1	(1,430)
2040	3235.1	1596.4			1783.0	(1,452)
2041	3258.8	1596.4			1784.8	(1,474)
2042	3282.6	1596.4			1786.7	(1,496)

Figure 6.1.1 shows a graphical depiction of WPL's load and capability position for the base case before the EGEAS supply expansion.

Figure 6.1.1 – WPL 2014 IRP – Load & Capability Before New Resource Additions



6.2 Detailed Support for Load and Capability Positions

Table 6.2.1 in Appendix 6A provides a calendar summary of the zonal resource capacities for each of the generating units based on October 31, 2013 capacity test data corresponding to the November 1, 2013 load forecast. This table includes both owned and PPA resources as described in Section 5 as well as some additional resources required for more near term needs out to 2017.

Table 6.2.2 in Appendix 6A provides a summary of the annual changes to supply-side resources for the first 8 years (2013 through 2020) of the load and capability position analysis. This table is based on the information provided in Table 6.2.2 in Appendix 6A and should help readers better understand the data.

Table 6.2.3 in Appendix 6A provides detailed support for the demand-side management resources classified as supply-side capacity in the load and capability analysis.

6.3 TREATMENT OF DEMAND-SIDE MANAGEMENT IN THE LOAD AND CAPABILITY POSITION

WPL has historically treated its interruptible demand response as a demand-side resource by netting from the peak load forecast, consistent with the MISO resource adequacy construct at the time. In 2014, the Federal Energy Regulatory Commission (FERC) approved MISO tariff changes to move such demand response resources from the load side to the supply side (Docket No. ER14-990). As a result of this change to the resource adequacy construct, beginning with the year 2014 WPL has classified its interruptible load as supply capacity and added it to its supply-side capacity resources instead of netting it from peak demand. According to the tariff change, the value of interruptible demand has been grossed up for transmission losses and the planning reserve margin. These calculations can be seen on Table 6.2.3 in Appendix 6A. Additionally, for modeling convenience, the 2013 interruptible demand is also classified as a supply-side resource.

7 RESOURCE PLANNING ALTERNATIVES

The WPL IRP contains two categories of new resource planning alternatives, hereinafter referred to as “planning alternatives.” The first category of planning alternatives is referred to as “demand side” which includes resources that can impact electricity demand from the MISO system. The second category is referred to as “supply side” which includes resources that can generate electricity and supply it to the MISO system. This section of the IRP provides an overview of the information sources and applications for supply-side and demand-side resources in the WPL IRP analysis.

7.1 INFORMATION SOURCES

The following subsections identify the information sources for the demand side and supply side resources that were evaluated in this IRP.

7.1.1 Demand Side

Two categories of demand side alternatives were evaluated in this IRP; a hypothetical Aggressive Demand Side Management (DSM) program, and several Distributed Generation (DG) technologies. These alternatives were discussed in detail in Section 3 and Section 4, respectively. Recall from those sections that the DSM information was developed by WPL and the DG data was developed by the outside consultant TetraTech.

7.1.2 Supply Side

The main source of cost and performance information for new generically priced and specified supply-side planning alternatives was obtained from the 2013 Power Station Characterization Study (B&V Study) that Black & Veatch developed for WPL. A copy of the B&V Study is included in Appendix 7A.

7.2 Alternatives Discussion

7.2.1 Wisconsin Energy Priorities Policy

For purposes of this IRP, both the supply-side and demand-side alternative technologies are evaluated according to the Wisconsin Energy Priorities Policy as stated in Wisconsin Statute 1.12 (4). The technologies identified for consideration in this IRP are listed in Table 7.2.1.1, ordered from highest to lowest priority assigned by the Statute.

Table 7.2.1.1 - Wisconsin Energy Priorities

Energy Priority	Technologies
(a) Energy Conservation and Efficiency	*Aggressive DSM
(b) Renewable, Noncombustible	*Wind
	*Solar-Photovoltaic
	Solar-Thermal
	Hydroelectric
	Geothermal
(c) Renewable Combustible	*Biomass
	Biogas Anaerobic Digestion
	*Biogas Landfill Gas
(d) Nonrenewable Combustible	*Combined Cycle
	*Combustion Turbine
	Integrated Gasification Combined Cycle
	Pulverized Coal

*These units were made available as new planning alternatives in the EGEAS analysis

7.2.2 Demand Side Resources

7.2.2.1 Energy Conservation and Efficiency (Aggressive DSM)

The first item in the State Energy Priorities is energy conservation and efficiency. As noted in Section 2 of this report, current levels of energy efficiency, as acquired by customers through the Focus on Energy program, are implicitly included in the forecasting data and hence the forecasting models and the forecasts themselves. This implicit energy efficiency did not receive any special treatment in the forecast, and therefore is treated as though the savings will be maintained throughout the duration of the forecast.

To address the prospect of satisfying load requirements with incremental energy conservation and efficiency, a hypothetical "Aggressive DSM" resource was specified in the EGEAS IRP model. The details about the Aggressive DSM program are provided in Section 3 of this report. For the context of this Section, the high points of the hypothetical Aggressive DSM program are:

- Costs determined by the difference between the average incremental costs in Iowa and Minnesota compared to actual WPL energy efficiency (EE) costs;
- Energy and demand savings were determined from the difference between the average incremental EE savings in Iowa and Minnesota compared to actual WPL EE savings;
- The program assumes a ramp-up period of two years to the point of initial participation; and
- The program takes on participants over five years with an assumed average program savings life of 12 years for each year of the program.

7.2.3 Supply Side Resources

7.2.3.1 Renewable, Noncombustible

Section 8 of the Black and Veatch (B&V) 2013 Power Station Characterization Study, hereinafter referred to as the “B&V Study,” focuses on renewable energy technology options. The non-combustible category of renewables refers to resources that do not require the combustion of any fuel in order to produce energy. Five renewable, noncombustible technologies were reviewed to satisfy item (b) of the Wisconsin energy priorities. These include wind, solar-photovoltaic, solar-thermal, hydro, and geothermal. Two of these resource, wind and solar-photovoltaic were included in the EGEAs model.

<u>Wind</u>

Wind power is a viable option to consider for new applications in WPL. Currently, WPL has contracted for approximately 170 MW (nameplate) of wind energy located in Wisconsin and Iowa. Additionally, WPL has installed 270 MW of owned-wind generation in Wisconsin and Minnesota (Cedar Ridge and Bent Tree).

Wind in Iowa and Minnesota has historically produced higher capacity factors than wind located in Wisconsin. For EGEAS modeling of new wind resources, WPL utilized an Iowa based capacity factor that is derived from actual operating data at Flying Cloud, an Iowa wind resource within Alliant Energy’s IPL utility. The capacity factor derived from this resource for EGEAS modeling purposes is approximately 41%. If new wind were to be located in Wisconsin, it is estimated that capacity factors would be approximately 35%, recognizing that wind profiles are not as advantageous in Wisconsin as they are in Iowa.

The current MISO construct is a zonal construct with Zone 2 relatively aligned with the Wisconsin state boundary, and Zone 3 relatively aligned with the Iowa state boundary. The transfer capability between zones in MISO limits WPL’s ability to transfer capacity between zones. Therefore, in this IRP, accredited capacity from new wind in Wisconsin was given credit toward the planning reserve margin requirement (PRMR) for the WPL utility while accredited capacity from new wind in Iowa was not.

During the development and tuning of the EGEAS model for this IRP, both the Wisconsin wind and Iowa wind units were included in the model. None of the runs performed yielded an expansion plan that gave preference to the Wisconsin wind over the Iowa wind, despite the nominal capacity credit from Wisconsin wind. When wind was selected in the expansion plan, it was always the higher capacity factor Iowa wind unit. For this reason, the Iowa based wind units were modeled as a resource option in the EGEAS analysis for this IRP.

The aforementioned Iowa based wind assumption was made for modeling purposes only. There have not been any management decisions to locate all future wind in Iowa; rather, this assumption was made for timely advancement of the EGEAS modeling process. This modeling assumption does not preclude WPL from considering Wisconsin based wind resources in its future wind resource developments.

Solar-Photovoltaic (PV)

With recent declines in capital costs, PV has achieved more consumer recognition over the last few years. The overnight cost[23] of commercial PV capacity, as developed in the B&V Study, was estimated to be between $[redacted] per kW and $[redacted] per kW for a facility of 10 MW with an approximate capacity factor of 20 percent. Solar PV was modeled as a resource option in the EGEAS analysis for this IRP.

Solar-Thermal

There are two general categories of solar energy that reach the ground. For the purposes of this IRP, they are referred to as "un-scattered," and "scattered." Un-scattered solar energy reaches the ground without any atmospheric losses due to scattering absorption. Scattered solar energy reaches the ground at an angle that is not parallel to the un-scattered direct energy from the sun.

While solar-photovoltaic can utilize both the scattered and un-scattered forms of solar energy, Solar-thermal systems can only utilize the un-scattered direct energy. This is due to the fact that solar-thermal systems utilize mirrors to concentrate the solar energy onto a focal point. Only the un-scattered solar energy reaches the mirrors at the correct angle to re-direct it to the focal point.

[23] Overnight cost in this IRP refers to the capital cost of new construction in 2013$ excluding escalation and AFUDC.

In order to be economically feasible, solar-thermal systems currently require a level of un-scattered direct energy that is not available in Wisconsin or the neighboring states. Solar-thermal systems were not included in the EGEAS analysis for this IRP.

Hydroelectric

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. The best sources of hydro generation in WPL's service territory have already been developed. New hydroelectric resources were not included in the EGEAS analysis for this IRP.

Geothermal

Geothermal power is limited to locations where geothermal pressure reserves are found. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installed. Because there are no known geothermal sources in this region suitable for utility scale energy generation, geothermal resources were not included in the EGEAS analysis for this IRP.

7.2.3.2 Renewable, Combustible

Three renewable, combustible, technologies were reviewed for inclusion in the EGEAS model: Biomass, Biogas-anaerobic digestion, and biogas-landfill gas. Of these three technologies biomass and landfill biogas were included in the EGEAS model for this IRP.

Biomass

Potential for power production from biomass combustion exists within WPL's service territory. Fuel stream limitations and higher capital costs make this option less attractive than other available alternatives; however, biomass was modeled as an option in the EGEAS analysis for this resource plan in order to satisfy item (c) of the energy priorities.

Biogas

Landfill Gas

From an energy generation perspective, Landfill gas (LFG) is a valuable resource that can be burned as fuel by reciprocating engines, small combustion turbine generators or other devices. Gas production in a landfill is primarily dependent upon the depth of waste in place, age of waste in place and amount of precipitation received by the landfill. There is limited potential for new power generation from LFG in WPL's service territory. The landfill biogas alternative was included in the EGEAS analysis for this IRP as an additional resource to satisfy item (c) of the energy priorities.

Anaerobic Digestion

The most common applications of anaerobic digestion use industrial wastewater, animal manure or human sewage. In agriculture applications, anaerobic digesters can be installed where there is a clean, continuous source of manure. For on-farm manure digestion, the resource is readily accessible and only minor modifications are required to the existing manure management techniques. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. WPL's service territory has potential for anaerobic digestion; however, due to the capital cost on a $/kW basis being significantly higher than landfill gas, anaerobic digestion was not modeled in EGEAS for this IRP.

7.2.3.3 Nonrenewable Combustible

Nonrenewable combustible technologies currently provide the majority of energy used by customers in the WPL service territory. Although preference is given to the higher energy priorities, nonrenewable combustibles resources are still considered the most likely to serve as intermediate and base load resources for utility scale capacity and energy needs due to the availability of reliable, low cost fuel sources.

Combined Cycle

The term "combined cycle" refers to the combination of two thermodynamic cycles into one complete process for energy generation. The first thermodynamic cycle, the Brayton cycle, is most commonly associated with a natural gas combustion turbine (CT) which combusts natural gas to produce mechanical, and subsequently electrical energy. The hot exhaust gas from the CT is then used to generate steam in a Heat Recovery Steam Generator (HRSG) which supplies energy to the Rankine cycle. The Rankine cycle describes the thermodynamic cycle of converting energy from steam into mechanical and subsequently electrical energy. By combining the Brayton cycle with the Rankine cycle, combustion turbines are able to produce more energy more efficiently than they are with solely the Brayton cycle. Due to the recently proposed EPA regulations for fossil-fuel fired generating units, natural gas combined cycle

(NGCC) resources are emerging in the United States as the replacement for intermediate and base load resources as coal units retire. WPL currently has one existing NGCC unit, Riverside Energy Center.

Two types of NGCC resources were modeled in the EGEAS analysis. They are referred to as 1x1 and 2:1 NGCC resources. The first number refers to the number of CTs and the second number refers to the number of HRSGs. A 1x1 has one CT and one HRSG. A 2:1 has two CTs and one HRSG. The size of these units can vary dependent on the manufacturers and options selected. The sizes of these units identified in the B&V study for proven NGCC technologies are approximately 300 MW for the 1x1 configuration and approximately 600 MW for the 2:1 configuration.

Combustion Turbine

CTs were described in the previous section as the Brayton cycle component of the Combined Cycle configuration. WPL has a number of CTs on its system. These units serve peak energy needs and generate only a small amount of the total electrical energy produced by WPL. The initial construction cost of CT units is less expensive than NGCC units per installed MW, and therefore can fill capacity needs at a lower cost than NGCC units. However, CTs are not expected to serve as intermediate or base load resources due to their inefficiency relative to NGCC units. CT units were included in the EGEAS analysis.

Pulverized Coal

Due to comparatively low fuel costs and mature technology, much of the energy generated on WPL's utility system is from units fueled by pulverized coal. However, due to recently proposed EPA regulations of CO2 emissions from new resources, which include limits for new coal units based on partial carbon capture and storage (CCS), coal is not viewed as a viable planning alternative and was not included in the EGEAS analysis.

Integrated Gasification Combined Cycle

The integrated gasification combined cycle (IGCC) application for power generation uses a coal gasification process. Due to recently proposed EPA regulations of CO2 emissions from new resources, which include limits for new IGCC units based on partial CCS, IGCC is not viewed as a viable planning alternative and was not included in the EGEAS analysis.

Nuclear

Nuclear power was not modeled as a resource alternative in the EGEAS analysis for this resource plan. In the recent past WPL has included nuclear power as a planning alternative in its EGEAS models. This was done in response to a concurring opinion in the final order in Docket No. 6630-CE-299, dated July 2008. This case was We Energy's application to construct a scrubber and SCR at its Oak Creek power plant.

A Commissioner's concurring opinion was made to address "(1) data needs for future pollution-control applications and (2) final orders capturing assurances made by the applicant." With regards to the first perspective, the opinion noted that Yucca Mountain had an anticipated on-line date of 2020, which would automatically lift a nuclear moratorium, and the (Wisconsin) Global Warming Task Force recommended lifting the moratorium.

As such, a nuclear unit with an on-line date of at least 2020 was included in prior EGEAS IRP models at the request of this opinion. Nevertheless, the state of Wisconsin continues to ban the development of nuclear power (Wisc. Stat. 196.493). Therefore, nuclear power was excluded as a resource alternative in this IRP.

Purchased Power

WPL purchases electrical energy from the MISO, other utilities, independent power producers and power marketers. The decisions regarding purchased power are primarily functions of need, availability and cost. WPL will continue to evaluate purchase power options for both short term and long term needs as it becomes available and economical.

Cogeneration/Distributed Generation

Cogeneration refers to facilities that produce electricity as well as other forms of energy. Section 4 of this resource plan details the distributed generation potential for this technology. Although DG was not modeled in EGEAS, the potential impact of DG was considered as explained in Section 4.

7.3 Alternatives Considered in Analysis

7.3.1 Future Resource Alternatives

As noted, the resource planning alternatives from the B&V study have been categorized and reviewed according to the Wisconsin Energy Priorities Policy. The units selected for consideration in the model also reflect the categorization of this policy. The EGEAS modeling includes the resources in Table 7.3.1 in all of the base and sensitivity EGEAS runs to ensure that a complete cross-section of the resource alternatives adhering to the state policy is tested for viability.

Table 7.3.1 WPL 2014 IRP Resource Planning Alternatives

Presented in the General Order Described Above

EGEAS Unit Name	**Description**
DDSM P 2016-2020	Aggressive DSM
WIND P 100MW WI	35% Capacity Factor – WI
WIND P 100MW IA	41% Capacity Factor – IA
SOLR P 10MW	PV 20.1% Capacity Factor
BIOM P 35MW	Direct-Fired Open-Loop Biomass
BIOG P 10MW	Landfill Gas
NCT2 P 192MW	GE 7F 5-Series CT
NCC1 P 300MW	1x1 GE 7F 5-Series CC
NCC2 P 605MW	2x1 GE 7F 5-Series CC
APUR P 50MW 1YR	MISO System Capacity Only

WPL is committed to meeting the demands of its customers with economic, reliable, safe, environmentally responsible resources. Furthermore, WPL's DSM programs and renewable resource portfolio demonstrate WPL's commitment to environmentally responsible resources as part of its resource mix.

Information as to the types, sizes, costs, and characteristics for all generic future units modeled in EGEAS for this resource plan are given in Table 7.3.2 in Appendix 7B. With respect to resource costs changing over time, nominal escalation rates for O&M expenses and capital investment can be found in Table 7.3.3 in Appendix 7C.

7.3.2 EGEAS "Detailed Costs"

This section also provides information about the EGEAS "detailed costs" modeled for resource planning alternatives in the last sub-section.

Section 5 of this report provides information about data modeled in the "detailed costs" module in the EGEAS model for Edgewater Unit 4 and Columbia Units 1 and 2 (see Table 5.1.3 in Appendix 5B). The "detailed costs" module of EGEAS gives modelers an opportunity to include costs for generating units that do not easily fit in other EGEAS categories or costs that may be specified separately from other unitized costs.

This section of the IRP report provides information about the EGEAS "detailed costs" specified for resource planning alternatives. These units include:

- DDSM P 2016-2020;
- WIND P 100 MW WI;
- WIND P 100 MW IA;
- SOLR P 10MW;
- BIOM P 35MW; and
- BIOG P 10MW;

The EGEAS "detailed cost" category was used to model the annual fixed O&M start-up costs of the aggressive DSM unit. The development of those costs is presented in Appendix 3A of Section 3 of this report.

For the wind, biomass, and biogas units, EGEAS "detailed cost" was used to model the production tax credit (PTC). For each of these units, an annual PTC value was calculated to represent the specifics of the PTC for wind, biomass, and biogas. The annual values were calculated in such a way as to compensate for an EGEAS modeling limitation. Namely, EGEAS is not capable of reserving a 10-year PTC stream to start at any time during the study period without being predetermined. To compensate for this lack of flexibility in the EGEAS model, 10-year PTCs are converted into levelized annual values to coincide with the book lives of the resources. By doing this the 10-year value of the PTC can be captured over the book life of the new unit regardless of when the units are deployed in the dynamic programing process. It should be noted that since the PTC for wind, biomass, and biogas has been converted to a 30-year levelized value, there is no need to specify a schedule reflecting year over year variations in the values. The values are the same for every year of the study.

Tables 7.3.4, and Table 7.3.5 in Appendix 7D provide summaries of the calculations for the PTCs and various intermediate results or steps to arrive at the PTC used for each of the wind, biomass, and biogas units listed above.

The foot note in Table 7.3.2 in Appendix 7B summarizes the specification for the investment tax credit (Solar ITC) used for the solar unit. Data for the Solar ITC was taken from a US Department of Energy web page.[24]

For renewables tax credits, particularly PTCs, there is not a long term forward looking tax policy in place to continue, or extend, the tax credits at recently observed levels. However, in recent history, PTC incentives have commonly been given short term extensions. For this IRP analysis, WPL needed to make a decision on whether or not to model continued extensions of these tax incentives. It was decided that the base case analysis would include continued extension of PTCs and ITCs at their recent levels indefinitely, and that Sensitivity 16 would not include any extension of PTCs and ITCs. Therefore, from a renewables tax policy perspective, the base case includes tax policy assumptions that favor renewables while Sensitivity 16 includes tax policy assumptions that do not favor renewables.

[24] http://energy.gov/savings/business-energy-investment-tax-credit-itc

8 RESOURCE PLAN

8.1 Overview

This section summarizes the methods by which the inputs described in Sections 2, 3, 5, 6, and 7 of this report are brought together, with other inputs described later in this section, in the EGEAS model to determine the best set of generation resources to serve projected capacity and energy obligations.

WPL has announced that it would be pursuing a generation resource with a capacity of 200 to 600 MW. This announcement was influenced, in part, as a result of the EGEAS analysis that WPL performed for its response to PSCW Staff data request for the 2014 Strategic Energy Assessment (Docket 05-ES-107). The need for the unit was publically announced in the November 7, 2013 release of Alliant Energy's US SEC Form 10-Q for the quarterly period ended September 30, 2013. This leads to one of the reasons for the preparation of the 2014 IRP as support for a CPCN filing expected in first quarter of 2015.[25]

The Strategic Overview of the November 7, 2013 SEC 10-Q stated that WPL is "planning for a new generation investment to address its customer energy and capacity needs in 2019 and beyond."[26] "Options under consideration include conversion of an existing natural gas-fired facility from simple-cycle to combined-cycle, or the construction of a new resource."[27] This defines two aspects of the scope of analysis needed for the CPCN support perspective of the 2014 IRP and associated EGEAS modeling: conversion of an existing asset or construction of a new resource.

The perspective taken in the 2014 IRP analysis is to determine, in a first-phase approach, the optimal choice among generic resource planning alternatives, as described in Section 7 of this report, to identify the optimal resource option to pursue. Further analysis is presented in the CPCN application itself to narrow the resource selection using this IRP as a point of departure to the next phase of analysis, recognizing the results of this IRP to carry forward the feasibility of alternatives such as converting an existing asset as noted in the above-cited 10-Q.

[25] A second reason for preparing the 2014 IRP was for the anticipated staff data request for the 2016 Strategic Energy Assessment performed by the Public Service Commission of Wisconsin.
[26] Alliant Energy Corporation, US SEC Form 10-Q for the quarterly period ended September 30, 2013, filed November 7, 2013, p. 49.
[27] *Id.*

8.2 LEAST-COST PLAN

The dynamic programming optimization standard used in the EGEAS modeling is to minimize the present value of annual revenue requirements (PVRR) for the 30-year planning period plus a 35-year extension period, while maintaining the MISO coincident peak planning reserve margin (PRM_{ucap}) of 7.3 percent in each year. As noted in the introduction, all combinations of existing resources are modeled with future resource alternatives to determine the optimal, least-cost expansion plan. Renewable alternatives, Demand-Side Management (DSM) programs and conventional supply-side units are all considered in this resource planning process. The ultimate goal is to minimize cost while maintaining system reliability requirements. Using reasonable assumptions and careful consideration of costs, reliability, and risks, the EGEAS analysis produced the base case expansion plan shown in Tables 8.2.1 and 8.2.2.

Table 8.2.1 Base Case Expansion Plan, Units Added by Year

Year	2:1 NGCC	1:1 NGCC	1:0 CT	Wind	Solar	Biomass	Biogas	Annual Capacity Purchase	DSM-Aggressive
2013	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	1
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	1	0
2019	1	0	0	1	0	0	0	0	0
2020	0	0	0	1	0	0	0	0	0
2021	0	0	0	1	0	0	0	0	0
2022	0	0	0	1	0	0	0	0	0
2023	0	0	0	1	0	0	0	0	0
2024	0	0	0	1	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	1	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	1	0	0	0	0
2031	0	0	1	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	1	0	0	0	0	0	0
2036	0	1	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	1	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	1	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0

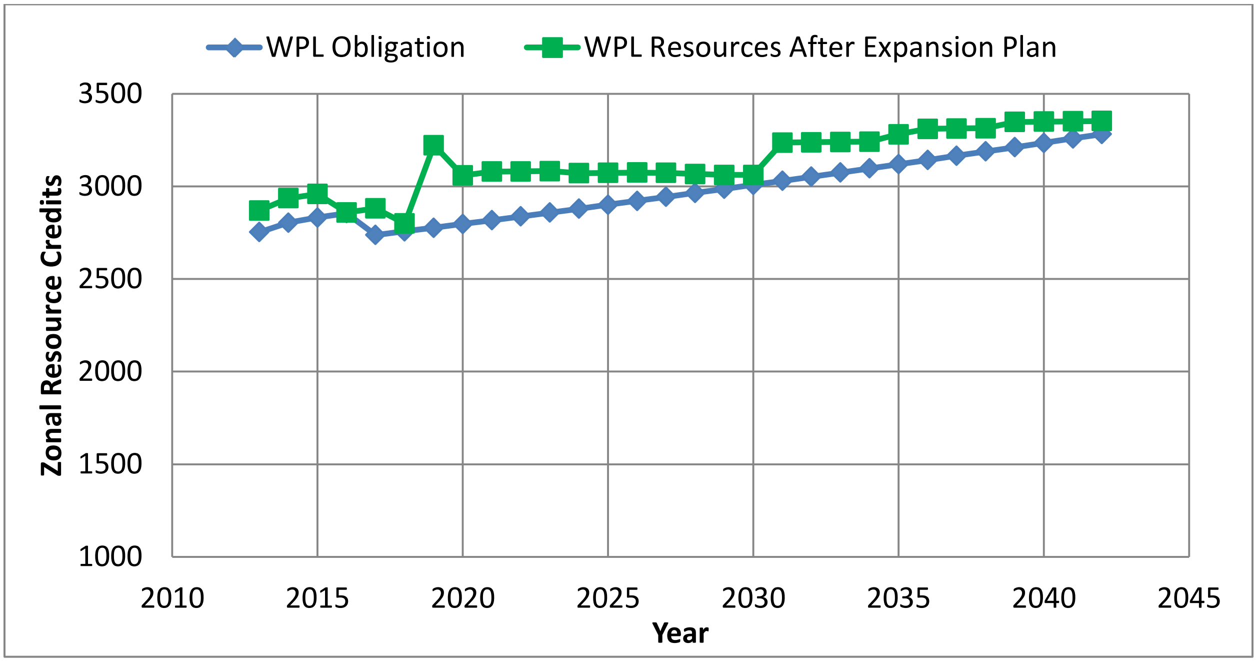
Table 8.2.2 Base Case Expansion Plan, Capacity Added by Year (MW, ZRCs)

Year	2:1 NGCC	1:1 NGCC	1:0 CT	Wind	Solar	Biomass	Biogas	Annual Capacity Purchase	DSM-Aggressive*
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	7.3
2019	573.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	6.2	0.0	0.0	0.0	0.0
2031	0.0	0.0	180.3	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	180.3	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	284.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	284.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

*The DSM program has a 12-yr life

Figure 8.2.1 provides the graphical depiction of WPL's load and capability position for the base case after the EGEAS expansion plan unit additions identified in Table 8.2.1 and Table 8.2.2.

Figure 8.2.1 – WPL 2014 IRP Load & Capability Position – After Resource Additions



8.3 EGEAS Modeling Inputs

This section provides an overview of the major assumptions used in the EGEAS model for the WPL 2014 IRP. These inputs are applied throughout the data sets for the base case and the sensitivities. The sensitivities are provided here in order to create context for some of the variations on the data inputs presented in the next few subsections. The sensitivity categories evaluated in the WPL 2014 IRP are as follows:

- Load Growth
- Market energy and capacity availability
- Gas Prices
- Coal Prices
- New gas unit capital costs
- No Production Tax Credits
- CO2 Sensitivity – Wood Mackenzie

8.3.1 General EGEAS Settings

Some notable general EGEAS settings include:

- 2013 through 2042 study period with a 35 year extension period;
- 7.82 percent discount rate (after tax weighted average cost of capital);
- 2012 Base year; and
- 7.3 percent UCAP planning reserve margin requirement[28].

8.3.2 Peak Load (Demand) and Annual Energy Forecasts

Section 2 of this report provides a detailed description of the peak load and energy forecasts. In summary, WPL developed a base, high, and low load forecast as shown in the Tables 8.3.2.1, 8.3.2.2, 8.3.2.3, respectively, in Appendix 8A. Appendix 8A also provides graphs showing the relative growth of the base, high, and low forecasts in Tables 8.3.2.4 and 8.3.2.5. Table 8.3.2.6 below shows the start and end values of these forecasts.

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[28] For modeling purposes, as described in Section 7, 10.358 percent was entered into the planning reserve margin field in EGEAS in order to incorporate both the MISO PRMR and transmission losses

Table 8.3.2.6 WPL 2014 IRP Base, High, and Low Peak Load Forecast Growth

Case	Forecast	Non-Coincident Peak Load (excludes wholesale contracts)	Adjusted Net Coincident Peak Demand Excluding Transmission Losses	Obligation: Including trans losses 2.85% and MISO PRM 7.3%
		(MW)	(MW)	(ZRC)
Base	2013	2,512.0	2,520.6	2,753.2
	2042	3,164.1	2,974.5	3,282.6
	Change	652.1	453.9	529.4
	Annual Compound Growth Rate	0.8%	0.6%	0.6%
High	2013	2,512.0	2,520.6	2,753.2
	2042	3,638.9	3,417.1	3,771.0
	Change	1,126.9	896.5	1,017.8
	Annual Compound Growth Rate	1.3%	1.1%	1.1%
Low	2013	2,512.0	2,520.6	2,753.2
	2042	2,748.8	2,587.4	2,855.4
	Change	236.8	66.8	102.2
	Annual Compound Growth Rate	0.3%	0.1%	0.1%

8.3.3 Fuel, Market Energy and Capacity Price Forecasts

Fuel and market energy and capacity prices are based on Wood Mackenzie projections. All of the forecasted fuel prices are presented in Appendix 8B. Table 8.3.3.1 (carbon and no-carbon) presents the coal price forecasts. In this table, coal prices are presented by fuel heat content and existing generating unit. Table 8.3.3.2 (no-carbon) presents the natural gas prices by existing unit either owned or leased by WPL. Table 8.3.3.3 (carbon) presents the natural gas prices by existing unit either owned or leased by WPL. Table 8.3.3.4 (carbon and no-carbon) presents the fuel oil prices. The Wisconsin River Power Company simple-cycle combustion turbine is the only generating unit modeled to use fuel oil.

Table 8.3.3.5 (carbon and no-carbon) provides the forecast of biomass and biogas fuel prices. Table 8.3.3.6 (carbon and no-carbon) provides MISO market energy prices for on-peak and around the clock generation. Table 8.3.3.7 (carbon and no-carbon) provides the MISO market capacity prices. There is no separate table for the fuel prices for the resource planning alternatives burning natural gas. The natural gas price forecasts for the Sheboygan Falls and

Neenah simple-cycle combustion turbine generating units are used for the resource planning alternatives burning natural gas.

8.3.4 Emission Allowance Cost and Tax Forecasts

Emission costs for SO2 and NOx are based on Wood Mackenzie projections. Due to significant fleet changes resulting from regulations such as Mercury and Air Toxics Standards (MATS) triggering retrofits, fuel switching, and retirements of units, Wood Mackenzie's SO2 and NOx prices are $[redacted] for the no-carbon and carbon regulation scenarios. This indicates a significant allowance supply surplus expected for future trading.

WPL uses the Wood Mackenzie carbon-regulation allowance prices. The forecast of these costs are described later in Section 8.5.2.7.

8.3.5 New Generic Generating Units (Resource Planning Alternatives)

New Generic Unit or Resource Planning Alternatives costs and parameters are noted in Section 7 of this report. Detailed base-year data are presented in Appendix 7B. This data is obtained primarily from the 2013 Power Station Characterization Study performed by Black & Veatch.

8.3.6 Capital and Operation and Maintenance (O&M) Cost Escalators

For existing generating units, the inclusion of on-going fixed (including both O&M and ongoing capital) costs was limited to only the generating units for which this type of information was anticipated as needed for performing analysis.

For resource planning alternatives (generic units), capital cost escalators are provided in Section 7 of this report in Table 7.3.3 in Appendix 7C.

Fixed and variable O&M cost escalators for existing generating units are included in the tables in Appendix 5B.The fixed and variable O&M escalators used for resource planning alternatives (generic units), are listed in the footnote of Table 7.3.2 in Appendix 7B.

8.3.7 Renewable Portfolio Planning Assumptions and Inputs

8.3.7.1 Renewable Portfolio Position

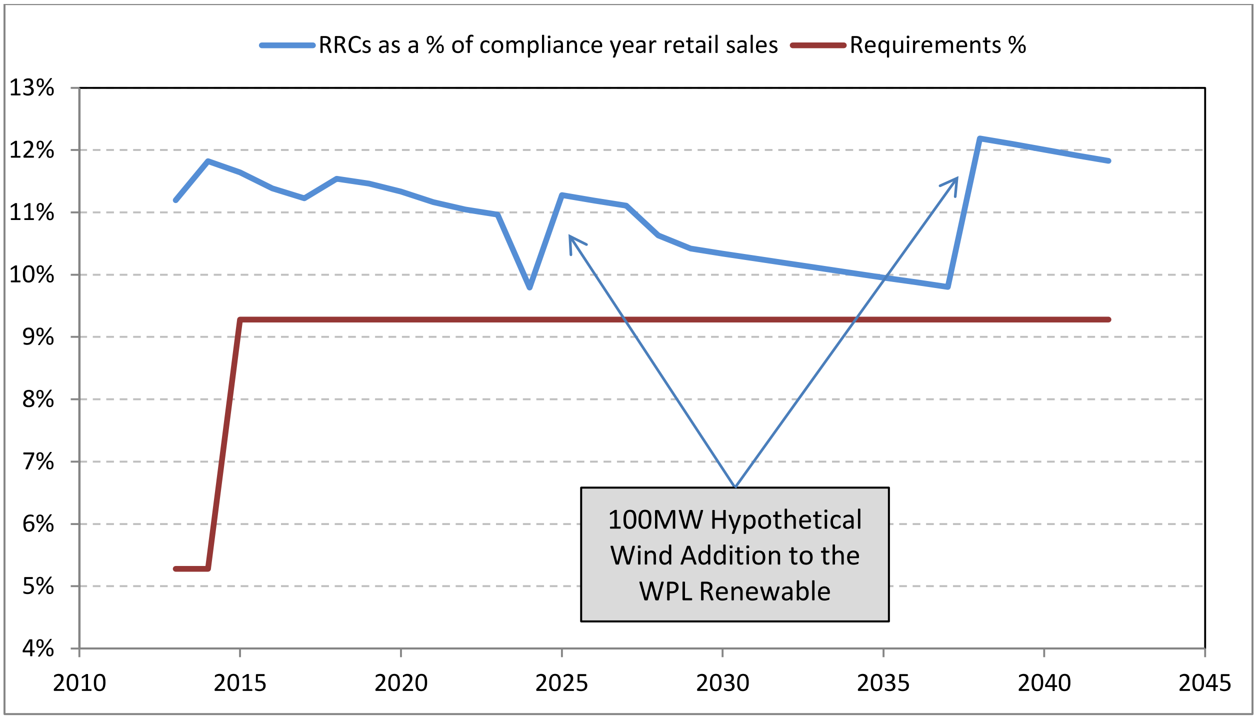
Wis. Stats. § 196.378 (Renewable Portfolio Standard (RPS)) establishes baseline renewable energy requirements as a percentage of previous three year average retail sales. The renewable requirements increase in steps over time above the baseline. WPL's required renewable portfolio is currently 5.28 percent for 2010 through 2014, and 9.28 percent for 2015 on. WPL's RPS position for 2013 was 11.25 percent of retail sales. WPL expects to remain compliant through 2024 with the use of the resources listed in Table 8.3.7.1.1 below.

Table 8.3.7.1.1 WPL 2014 IRP - Resources Used by WPL to Satisfy its Wisconsin RPS

Facility Name	Type	Modeled in EGEAS in WPL 2014 IRP
WPL Owned		
Bent Tree	Wind	Yes
Cedar Ridge	Wind	Yes
Prairie du Sac	Hydro	Yes
Kilbourn	Hydro	Yes
Petenwell	Hydro	Yes
Castle Rock	Hydro	Yes
Other Owner		
Crystal Lake II	Wind	Yes
Forward Energy	Wind	Yes
Montfort (Badger, Edonomont)	Wind	Yes
Top of Iowa	Wind	Yes
Valley Trail (Berlin)	Biogas, Landfill Gas	No
Ameresco Janesville 1/2 to SN	Biogas, Landfill Gas	No
Clear Horizons Dane Digester	Biogas, Digester	No
Forward Energy Second Nature Use	Wind	No

The EGEAS model includes wind generation as a resource planning alternative to be selected for economic additions if it supports the least-cost plan. In order to ensure that the base case and sensitivities satisfy the Wisconsin RPS, a minimum amount of cumulative renewable additions must be specified in the model. Therefore, renewable modeling includes, as one criterion, the necessity to add a 100 MW wind unit in each of 2025 and 2037. The impact on the WPL Renewable Resource Credits (RRCs) is illustrated in Figure 8.3.7.1.1 below.

Figure 8.3.7.1.1 – WPL 2014 IRP – Wind Additions Required for Wisconsin RPS



8.3.7.2 General Assumptions for Renewable Planning Alternatives

Table 8.3.7.2.1 provides a synopsis of assumptions regarding location, capacity factors (for non-dispatchable (NDT) units only), MISO capacity credit, production tax credit, and investment tax credit. Table 7.3.2 in Appendix 7B provides greater detail of information regarding the renewable resource planning alternatives.

Table 8.3.7.2.1 – WPL 2014 IRP - Synopsis of Assumptions for Renewable Alternatives

Resource Type	EGEAS Unit Name	Location	Capacity Factor NDTs Only	MISO Capacity Credit (MW)	Production Tax Credit 2013 $/MWH	Investment Tax Credit
Wind	WIND P 100MW IA	Iowa	41%		2.3	N/A
Solar	SOLR P 10MW	Wisconsin	20.3%	6.2	N/A	Pre-2016 30% level, 2013-2042
Biomass	BIOM P 35MW	Wisconsin	N/A	32.9	1.1	N/A
Biogas	BIOG P 10MW	Wisconsin	N/A	9.4	1.1	N/A

8.3.8 Existing Resources

A detailed summary of WPL's existing resources was described in Section 5 of this report. Within that section, Table 5.1.1 lists WPL's existing generating units in the order presented in the EGEAS model, and includes unit names, summer reserve ZRCs, unit ownership or PPA status, fuel or motive force, full-load heat rate, fuel cost ($2013), and variable O&M ($2013).

8.3.9 Generating Unit Retirements and Discontinued Power Purchase Agreement (PPA) Assumptions

This section of the report identifies generating unit retirements and PPA discontinuances occurring within the 30-year IRP study period. The generating unit retirements occurring within this period are classified as either publically announced, or confidential for planning purposes. Discontinuance of PPAs are classified as confidential. The details of these classifications are presented in this section and in Table 8.3.9.2.1 below.

8.3.9.1 Publically Announced Generating Unit Retirements

In section 4 of the Consent Decree in Civil Action Nos. 13-cv-266 and 13-cv-265, Dated April 22, 2013, and approved June, 2013, WPL has been ordered to retire, refuel, or repower generating units Nelson Dewey 1 and 2 and Edgewater 3 by no later than December 31, 2015. In the same section of the same document, WPL and Wisconsin Public Service, ownership partners, have been ordered to ensure that generating unit Edgewater 4 is retired, refueled, or repowered by no later than December 31, 2018.

On July 27, 2012 WPL publically announced plans to retire coal units Edgewater Unit 3 and Nelson Dewey Units 1 and 2 by December 31, 2015 and either convert to natural gas or retire Edgewater Unit 4 by December 31, 2018. In this 2014 IRP, WPL has modeled Edgewater Unit 3 and Nelson Dewey Units 1 and 2 to retire at the end of 2015 and Edgewater Unit 4 as retiring at the end of 2018.

8.3.9.2 Retirements Specified for Planning Purposes Only

WPL's load and capability position, as depicted in section 6, includes generating unit retirements other than the above-listed coal units. Those retirements that are planned to occur within the 30-year IRP study period are summarized in Table 8.3.9.2.1. This table provides sufficient details for readers to find the units in the EGEAS model and to generally understand why the generating unit retirement or PPA discontinuance is planned. These unit retirement and PPA discontinuances are stated for planning purposes only, and do not suggest that management decisions have been made to carry out these retirements or discontinuances.

Table 8.3.9.2.1 – WPL I2014 IRP - Long Standing Generating Units and PPAs Retired During the Study Period – (Confidential Data Highlighted in Gray)

Resource	Last Operating Year	EGEAS Modeled Retirement Year	Planning Assumption for Retirement*
Top of Iowa 1 (Worth)	[redacted]		
Forward II	[redacted]		
Cristal Lake 2	[redacted]		
Monfort	[redacted]		
Rock River Unit 3	2019	2019	Resource Adequacy Management
Rock River Unit 4	2019	2019	Depreciation Schedule
Rock River Unit 5	2019	2019	Depreciation Schedule
Rock River Unit 6	2019	2019	Depreciation Schedule
Sheepskin Unit 1	2019	2019	Resource Adequacy Management
South Fond Du Lac Unit 2	2034	2034	Depreciation Schedule
South Fond Du Lac Unit 3	2034	2034	Depreciation Schedule
Edgewater Unit 3	2015	2015	Consent Decree, US District Court
Edgewater Unit 4	2018	2018	Consent Decree, US District Court
Columbia Unit 1	2035	2035	Depreciation Schedule
Columbia Unit 2	2038	2038	Depreciation Schedule
Nelson Dewey Unit 1	2015	2015	Consent Decree, US District Court
Nelson Dewey Unit 2	2015	2015	Consent Decree, US District Court

*This analysis assumes planning assumptions for retirement of these units. WPL will, however, maintain flexibility with the retirement of these units through continued evaluation of MISO resource adequacy requirements, unit condition, and market conditions. Actual retirement dates may differ.

8.4 MODELING THE BASE CASE

The next general step in the IRP analytical process is to construct the base case, also referred to as a reference case. This base case reflects the general modeling assumptions, the base-line peak and energy (load) forecast, calibrations of thermal dispatchable units to levels of historical capacity factors (annual operating times) and compliance with emission caps.

8.4.1 Calibration of Thermal Dispatchable Generating Units

The coal-fired units were calibrated to annual output levels for select operating years using a capacity-factor limiting algorithm to determine non-base, block-loading outage rates. The energy output of the following list of coal-fired units was calibrated using historical operating data.

- Edgewater Unit 4;
- Edgewater Unit 5;
- Columbia Unit 1;
- Columbia Unit 2;
- Nelson Dewey Unit 1, and
- Nelson Dewey Unit 2.

In order to reflect historic unit operations, the existing and planning resource alternative simple-cycle combustion turbine generating units were limited to produce no more than five percent capacity factors.

8.4.2 Calibration of Coal Units to Satisfy the US District Court Consent Decree

The Consent Decree in Civil Action Nos. 13-cv-266 and 13-cv-265, dated April 22, 2013 and approved June 2013 "establishes emission rate limits for SO2, NOx and PM [particulate matter] for Columbia Units 1 and 2, Nelson Dewey Units 1 and 2 and Edgewater Units 4 and 5. The Consent Decree also includes annual plant-wide emission caps for SO2 and NOx for Columbia, Edgewater and Nelson Dewey."[29] The emission outputs for Columbia Units 1 and 2, Nelson Dewey Units 1 and 2, and Edgewater Units 4 and 5 were compared to the Consent Decree emission caps and maximum annual unit output was calibrated accordingly so that the corresponding annual emission caps were not exceeded.

[29] Alliant Energy 2013 Annual Report, p. F-99

8.5 General Modeling Results

The results of the completed EGEAS modeling runs are summarized in Tables 8.5.1a, 8.5.1b, 8.5.1c, and 8.5.1d as presented in Appendix 8C.

Table 8.5.1a lists the sensitivity categories, the specific case descriptions and the PVRR of each of the runs. This table also indicates the PVRR relationship of the sensitivities to the base case for the runs with and without the EGEAS extension period.

Table 8.5.1b lists the sensitivity categories, the specific case descriptions, and a matrix of sensitivity run descriptions that compliments Table 8.5.1a.

Table 8.5.1c lists the sensitivity categories, the specific case descriptions, and a summary of the expansion plans produced by the dynamic programming function in EGEAS.

Table 8.5.1d provides a referential time line of calendar years and study years to help readers follow the results in Table 8.5.1c. The results presented in these tables are summarized in the next eight subsections of this report.

It is strongly recommended that a printed copy of these tables is available for reference while reading the following subsections. The tables are formatted for printing on 11x17 sheets of paper. All four tables will print on one sheet.

8.5.1 Case 1: Base Case (Reference Case)

At the beginning of Section 8, it was noted that one purpose of this 2014 IRP was to determine, in a first-phase approach, the optimal choice among generic resource planning alternatives to pursue as a new generation resource. In WPL's response to staff data request for the 2014 Strategic Energy Assessment, it was noted that the company would be pursuing a generation resource of 200 to 600 MW capacity as a result of the EGEAS analysis. This need was publically announced in the November 7, 2013 release of Alliant Energy's US SEC Form 10-Q for the quarterly period ended September 30, 2013.

The base case reconfirms the findings in WPL's data response to the 2013 PSCW's Strategic Energy Assessment data request. That is, the pursuit of a generation resource of 200 to 600 MW of capacity to serve future load. An examination of Table 8.5.1c supports this conclusion. This table shows that the optimal plan, as determined by the PVRR in the base case, is to add a 2 by 1 natural gas combined cycle (2:1 NGCC) generating unit of 605 MW rated capacity in 2019. The table also shows that additional 1 by 1 NGCC units would be added in 2036 and 2039 and two simple-cycle combustion turbines (1:0 CT) in 2031 and 2035. The base case also features 8 additions of the Iowa energy-only wind unit, the addition of a solar unit in 2030 and 1 MISO market capacity purchase in 2018. Finally, in the base case, EGEAS deploys the aggressive DSM unit in 2016, demonstrating that DSM does not displace the need for a new 2:1 NGCC resource.

8.5.2 Modeling Sensitivities

Once the base case is established, the sensitivities listed in section 8.3 above and as follows (as they appear in Tables 8.5.1a, b, and c) are run as "one-off" modifications to the base case to test the strength or robustness of the model in the base case EGEAS analysis:

- Load Growth
  - High load forecast
  - Low load forecast
- Market energy and capacity availability
  - No market energy
  - Available market capacity
- Gas Prices
  - Gas prices increased by 10%, On-peak energy prices increased by 10%
  - Gas prices increased by 20%, On-peak energy prices increased by 20%
  - Gas prices increased by 30%, On-peak energy prices increased by 30%
  - Gas prices decreased by 10%, On-peak energy prices decreased by 10%
  - Gas prices decreased by 20%, On-peak energy prices decreased by 20%
  - Gas prices decreased by 30%, On-peak energy prices decreased by 30%
- Coal Prices
  - Coal prices increased by 10%, Around the clock energy prices increased by 10%
  - Coal prices decreased by 10%, Around the clock energy prices decreased by 10%
- New gas unit capital costs
  - New gas unit prices increased by 10%
  - New gas unit prices decreased by 10%
- No Production Tax Credits
- CO2 Scenario – Wood Mackenzie

Sensitivity cases will show if a change to any one particular input assumption is strong enough to change the expansion plan. Sensitivities give insights about how a base-case expansion plan might respond to variations in key variables like load forecasts, fuel costs, and resource planning alternative capital costs.

The following seven subsections briefly discuss the general set of sensitivities that were run. Subsequently, in section 8.6, the results of the base case and the sensitivities in terms of PVRR and expansion plans are reviewed.

8.5.2.1 Cases 2 and 3: Load Growth Sensitivities

The base, high, and low load forecasts and associated ZRC obligations used in the EGEAS model are provided in Table 8.5.2.1.1 in Appendix 8D. The high and low forecast are differentiated from the base forecast by adding and subtracting to the growth rate of the base forecast 0.50 percent or 50 basis points, respectively.

Table 8.5.1a in Appendix 8C shows the PVRR with the extension period for these sensitivities at \$11,480m and \$9,592m for the high forecast and low forecast, respectively.[30] These values vary from the base case PVRR with extension by \$1,057m and -\$831m, respectively.

Case 2

> Higher loads typically command more resource deployment as shown in Table 8.5.1c. One more each of the 1:1NGCC and 1:0 CT are added as well as one more wind unit and two more solar units, when compared to the base case.

Case 3

> The opposite is true for lower load forecasts. Table 8.5.1c shows that two less 1:1 NGCC and 1:0 CT units are deployed compared to the base case. Also, two fewer wind units are deployed compared to the base case and no solar or one-year market capacity purchases (APUR) are made compared to the base case.

Of particular note is that both the high and low forecast sensitivities show the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.2 Case 4 and 5: Market Energy and Capacity Availability Sensitivities

Case 4 and 5 vary MISO market energy and capacity availability. Case 4 assumes no availability of market energy, and Case 5 assumes increased availability of market capacity.

[30] PVRR comparisons in this section of the report include the 30-year study period plus a 35-year extension period.

Table 8.5.1a in Appendix 8C shows the PVRR with the extension period for these sensitivities at $10,606m and $10,358m for Case 4 and Case 5, respectively. These values vary from the base case PVRR with extension by $183m and -$65m, respectively.

Case 4

When assuming that no market energy is available, EGEAS will need to deploy more generating units to satisfy energy needs as noted in Table 8.5.1c in Appendix 8C. As a result, the two 300 MW 1:1 NGCC units deployed in 2036 and 2039 in the base case are replaced with a single 2:1 NGCC 605 MW unit which occurs five years prior, in 2031. The 1:0 CTs deployed in 2031 and 2035 in the base case are deferred to 2038 and 2039 in Case 4. The wind farm, solar, APUR, and aggressive DSM deployments in the base case remain unchanged.

Case 5

In the base case, WPL applies the MISO assumption that there may be a shortage of capacity available to satisfy planning reserve margin requirements. This assumption is applied by not allowing annual market capacity purchases after 2018. In Case 5, this MISO assumption is relaxed by allowing up to 150 MW of annual purchases (3 units), beginning in 2019 through the end of the study period. As a result, the two 1:0 CT units in 2031 and 2035 are deferred to 2039 and 2040. Additionally, two 1:1 NGCC units in 2036 and 2039 in the base case were replaced with a 2:1 NGCC in 2035. The wind and aggressive DSM deployments remain unchanged. Additionally, the solar unit does not get deployed. A series of one-year capacity purchases were selected in this case which allowed for the aforementioned adjustments to the expansion plan.

Again, of particular note is that both the no market energy and the available market capacity sensitivities show the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.3 Cases 6 – 11: Gas Price Sensitivities

To assess the impact that varying natural gas price has on the base case, the year-to-year forecasted natural gas prices were varied by a plus and minus 10, 20, and 30 percent. Cases 6-8 assume increases in gas price while cases 9 – 11 assume decreases in gas price.

- Gas Prices +10%; On-pk market energy Prices +10%
- Gas Prices +20%; On-pk market energy Prices +20%
- Gas Prices +30%; On-pk market energy Prices +30%
- Gas Prices -10%; On-pk market energy Prices -10%
- Gas Prices -20%; On-pk market energy Prices -20%
- Gas Prices -30%; On-pk market energy Prices -30%

Methodologically, the percentage changes in each sensitivity were made to the base-year prices and the base-case escalation pattern over the forecast horizon remained unchanged in all six of the gas price sensitivities. This has the effect of shifting the forecasted prices either up or down parallel to the base year-to-year escalated price pattern. Also, market-energy on-peak prices were varied by the same percentage as natural gas prices in each of the sensitivities. This assumes that the price of on-peak market energy is correlated to the price of natural gas burning resources such as simple-cycle combustion turbines.

<u>Cases 6 – 8</u>

Table 8.5.1c shows the expansion plans for the higher gas price sensitivities. Increasing gas prices by 10, 20, and 30 percent, does not change the expansion plan from the base case. The PVRR for these sensitivities (Table 8.5.1a) are $319m, $629m, and $935m, respectively, higher than the base case as expected due to higher costs of gas.

Cases 9 – 11

Turning to the gas price reduction sensitivities, Table 8.5.1c shows the expansion plan for Case 10 most closely resembles the base case, except for the advancement of the 1:0 CT by one year, the deferral of four wind units, a reduction in wind units from eight to six, and the elimination of a solar unit.

The expansion plans for Cases 9 and 11 both differ from the base case by eliminating the addition of the 1:1 NGCC units in 2036 and 2039. They also add a 2:1 NGCC in 2031. Case 9 does not change the wind, solar, APUR, and DSM expansions from the base case. Case 11 does reduce the wind unit expansions from eight in the base case to five by deferring additions from the 2019 to 2023 time frame to the 2024 to 2041 time frame.

All of the natural gas price sensitivities show the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.4 Cases 12 and 13: Coal Price Sensitivities

To assess the impact that coal price variation has on the base resource plan, the year-to-year forecasted coal prices were varied by a plus and minus 10 percent. This was done in Cases 12 and 13 listed below:

- Coal Prices +10%; Around the clock energy prices +10% and
- Coal Prices -10%; Around the clock energy prices -10%

Similar to the natural gas price sensitivities, the percentage changes in coal price were made to the base-year prices, and the base-case escalation pattern over the forecast horizon remained unchanged. This has the effect of shifting the forecasted prices either up or down parallel to the base year-to-year escalated price pattern. Also, market-energy around the clock prices were varied by the same percentage as coal prices in each of the sensitivities. This assumes that the price of around the clock energy has a correlation to base-load coal-fired resources.

Table 8.5.1c shows the expansion plans for the coal-price sensitivities. The expansion plans in the coal price sensitivities have only minor variation from the base case. In both Case 12 and Case 13, the EGEAS model deploys the same number and timing of units as the base case with one exception. In Case 13, the four wind units installed in 2021 through 2024 in the base case are deferred to 2022 through 2025.

The PVRR for these sensitivities, as listed in Table 8.5.1a, are $286m increase and $304m decrease for Case 12 and Case 13, respectively, relative to the base case PVRR.

Consistent with Case 1 through Case 11, the coal-price sensitivities also show the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.5 Cases 14 and 15: New Gas Unit Capital Cost Sensitivities

Two sensitivities, Case 14 and Case 15, were run to test the base case's response to changes in new gas unit capital costs as follows:

- New Gas Unit Prices +10%; and
- New Gas Unit Prices -10%

As with the sensitivities performed on natural gas and coal prices, the changes to annual capital cost for the natural gas alternatives were made to the base-year costs, and the escalation pattern over the forecast horizon remained unchanged.

Table 8.5.1c shows the expansion plans for these sensitivities. Case 14 did not change the expansion plan for the base case. Case 15 left the base case expansion plan nearly unchanged. The exception was an advancement of a 1:0 CT in 2031 in the base case to 2030 in Case 15.

The PVRR for these sensitivities, as shown in Table 8.5.1a, are a $107m increase and a $107m decrease for Case 14 and Case 15, respectively, relative to the base case PVRR.

Consistent with the expansion plan in Case 1 through Case 13, the natural gas unit capital cost sensitivities show the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.6 Case 16: No Production or Investment Tax Credits Sensitivity

The base case includes an assumption that tax policy will continue to provide incentives for new renewable resources. This assumption was implemented by retaining production tax credits (PTCs) for wind, biomass and biogas, and investment tax credits (ITCs) for solar. In Case 16, the assumed extension of these tax credits is removed. This sensitivity represents a scenario in which tax policy does not provide tax credits for renewable technologies.

As generally could be expected, fewer wind units are added (five fewer) in Case 16, with the first one in 2025 and the second one in 2038. The model still adds a solar unit in 2030 and the APUR and DSM additions are the same as in the base case. The two 1:1 NGCC units that the base case adds in 2036 and 2039 are eliminated, but a 2:1 NGCC unit was added in 2031.

The PVRR for this sensitivity, as shown in Table 8.5.1a, is a $260m increase relative to the base case PVRR.

Also, the expansion plan for this sensitivity shows the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.5.2.7 Case 17: Carbon Dioxide (CO2) Regulation

Case 17 is a carbon regulation sensitivity using data provided by Wood Mackenzie. The base case and all sensitivities other than Case 17 in the WPL 2014 IRP assume no carbon regulation and thus no incremental carbon production costs over the forecast horizon. The carbon regulation sensitivity uses Wood Mackenzie data and assumptions. These come from Wood Mackenzie's H2 November 2013 long-term forecast.

Wood Mackenzie assumes that carbon control will begin in 2023. Table 8.5.2.7.1 below shows the nominal carbon regulation prices used in the EGEAS model for this sensitivity.

Table 8.5.2.7.1

WPL 2014 IRP CO2 costs, $/short ton (nominal), Confidential

Developed from Wood-Mackenzie FAll H2 2013 Long Term Outlook
2 percent per year escalation past 2035 through the extension period.
EGEAS study period 2014-2042, 35 year extension period begins 2043

Year	No Carbon Regulation	Carbon Regulation
2013	$0.00	$0.00
2014	$0.00	$0.00
2015	$0.00	$0.00
2016	$0.00	$0.00
2017	$0.00	$0.00
2018	$0.00	$0.00
2019	$0.00	$0.00
2020	$0.00	$0.00
2021	$0.00	$0.00
2022	$0.00	$0.00
2023	$0.00	[redacted]
2024	$0.00	
2025	$0.00	
2026	$0.00	
2027	$0.00	
2028	$0.00	
2029	$0.00	
2030	$0.00	
2031	$0.00	
2032	$0.00	
2033	$0.00	
2034	$0.00	
2035	$0.00	
2036	$0.00	
2037	$0.00	
2038	$0.00	
2039	$0.00	
2040	$0.00	
2041	$0.00	
2042	$0.00	

In addition to the inclusion of CO_2 emission costs in Case 17, various other associated input assumptions were also changed to reflect the impact of CO_2 regulation as follows:

- On-peak economy energy prices (higher)
- Around the clock economy energy prices (higher)
- Coal fuel prices for existing units (lower)
- Natural gas prices for existing and future units (higher)

The values for each of the above assumptions for the CO_2 sensitivity were also developed by Wood Mackenzie.

Table 8.5.1c in Appendix D shows the variation in resource planning alternative deployment for the carbon regulation sensitivity. The only difference in unit deployment between Case 17 and base case is in the deployment of gas-fired generation after 2019. In the carbon regulation case, neither of the 1:1 NGCC units that were deployed in the base case in 2036 and 2039 are deployed; rather, a 2:1 NGCC unit is deployed in 2031.

Table 8.5.1a shows that the difference in PVRR with extension period for the carbon regulation case versus the base case is $1,569m. This is an expected result due to the added cost of carbon regulation.

Consistent with all other sensitivities, the expansion plan for this sensitivity shows the need for a 2:1 NGCC in 2019, thereby contributing to the robustness of the base case.

8.6 Strength or Robustness of the Base Case Plan

The sensitivity analyses conclude that the base case is very robust. This is discussed in the following subjects:

- Load and capability position;
- Resource planning alternatives deployed in each of the modeling sensitivities; and
- Energy balance and fuel diversity that would result from adding a gas-fired intermediate resource.

Each of these points are discussed in turn.

8.6.1 Load and Capability Position Graphs

The load and capability graph, before the inclusion of new resources, for the base case expansion plan in Figure 6.1.1 shows capacity deficiency beginning in 2019 without resolution. In contrast, the graph with inclusion of new resources, Figure 8.2.1, shows continuous capacity sufficiency throughout the planning horizon. Figure 8.2.1 reflects capacity additions as presented in the base case EGEAS output.

8.6.2 Sensitivity Analysis

The resource planning alternatives deployed in each of the modeling sensitivities also supports the robustness or strength of the base case. As a synopsis of the review of resource planning alternatives deployed in each of the sensitivities, the following general observations were made:

- In all cases, including the base case, a 2:1 NGCC unit is deployed in 2019;
- In all cases, by 2036 either a second 2:1 NGCC is deployed or two or more 1:1 NGCC units are deployed;
- In 13 of 17 cases, including the base case, seven wind units are deployed by 2028; the four exceptions include:
    - Case 3: The low load forecast case;
    - Case 10: Natural gas prices reduced by 20 percent;
    - Case 11: Natural gas prices reduced by 30 percent; and
    - Case 16: No production or investment tax credits.
- Most cases deploy one or more solar units by about 2030; the three exceptions include:
    - Case 3: The low load forecast;
    - Case 5: Available market capacity; and
    - Case 10: Natural gas prices reduced by 20 percent;
- All sensitivities select the unit representing an aggressive DSM program.

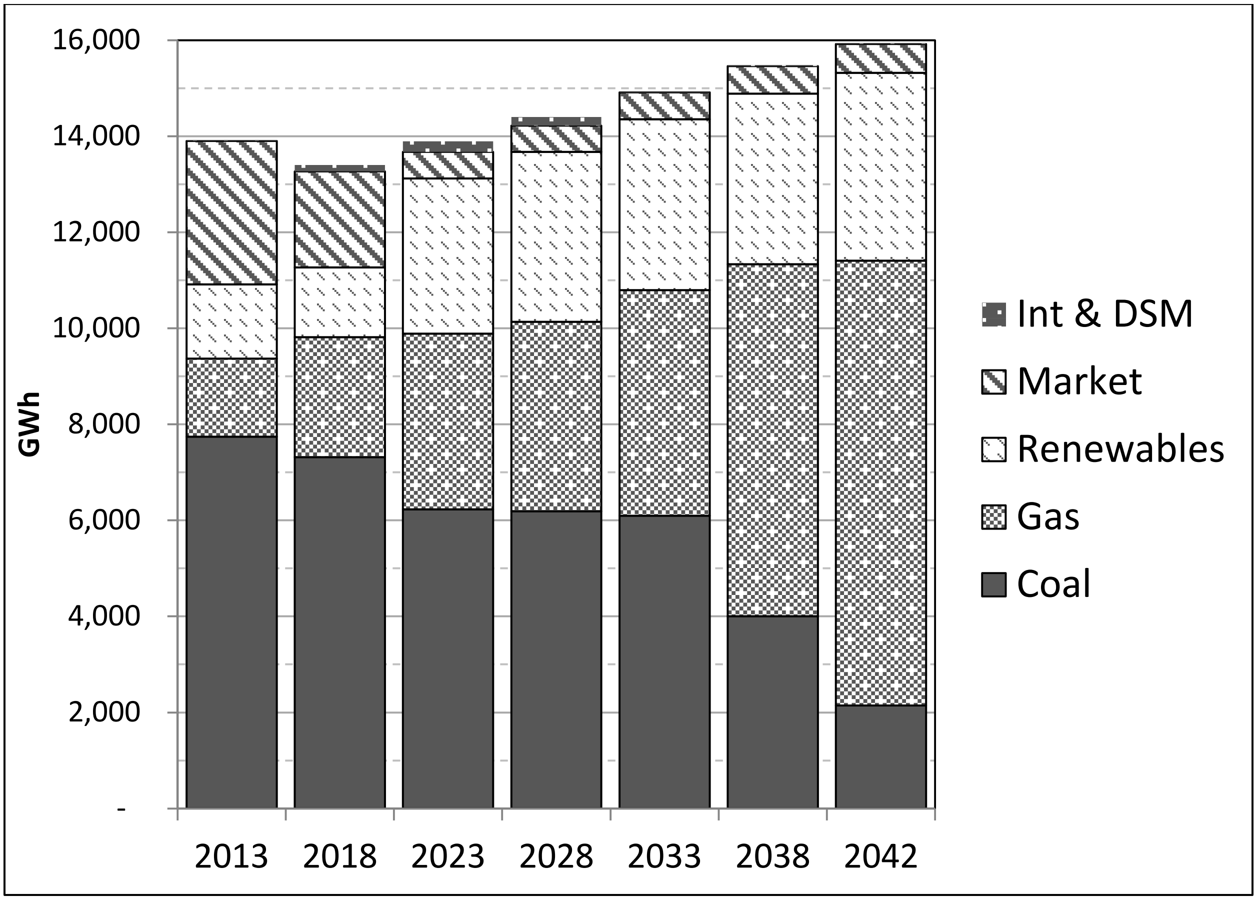
In essence, the sensitivities run for the WPL 2014 IRP unanimously point to a 2:1 NGCC unit in 2019 as well as additional NGCC installations over the 2025 through 2039 time period. With regards to renewables, many of the sensitivities support additional wind in 2019 through 2024 as complimentary resources to the 2019 2:1 NGCC. Recall that in all cases, except for case 16, the wind additions are predicated on the modeling assumption that tax policy will continue to support PTC for new wind resources.

8.6.3 Energy Balance and Fuel diversity

Diversity in fuels and technologies insulates against adverse movements in any one of these particular areas. This diversity is advantageous when attempting to take a reasonable cost path while maintaining a balanced and reliable portfolio when meeting the needs of WPL's customers.

Figure 8.6.3.1 shows the relative energy production by general resource type. Relative production proportions are shown for the base case study first year and every five years thereafter.

Figure 8.6.3.1 – WPL 2014 IRP – Energy Production by Resource Type

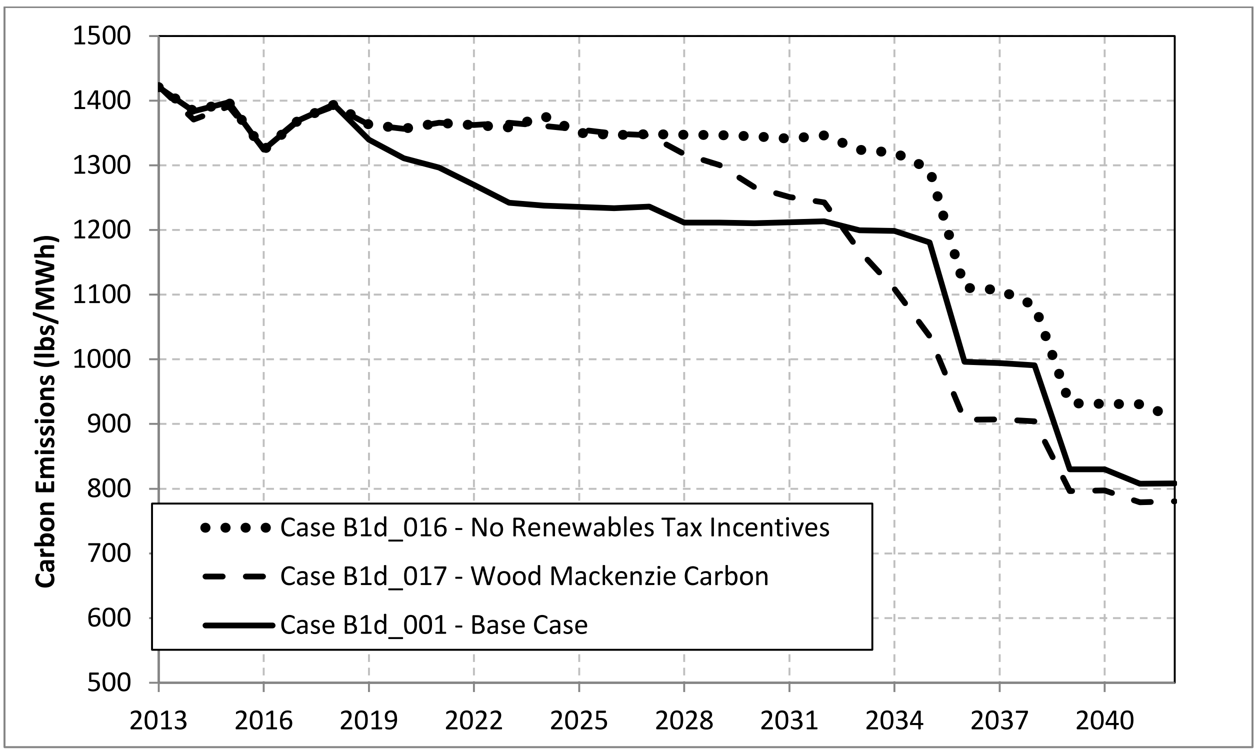


With a diverse and balanced portfolio, WPL will have more resource flexibility in a period of time when the electric utility industry is facing emission regulation uncertainty.

8.7 Carbon Emissions Regulation in Cases 1, 16, and 17

Although Case 17 was the only case that specifically identified a carbon price, Cases 1 and 16 are also important when evaluating potential carbon emissions in the expansion plan. Recall from Section 7.3.2 that WPL assumed the indefinite extension of renewables tax incentives in the base case analysis, and that Sensitivity 16 assumed no extension of renewables tax incentives. Since carbon emissions are heavily impacted by the volume of renewables in a generation portfolio, the carbon emissions from Cases 1 and 16 should be included in any analysis of potential carbon emissions. Figure 8.7.1 illustrates that the extension of renewables tax credits (Case 1) results in a larger reduction in carbon emissions than the Wood Mackenzie carbon price (Case 17) through 2033, when compared to the case without renewables tax incentives or a carbon price (Case 16). This is driven by the early economic selection of new wind units in Case 1. After 2033, Case 17 provides a larger carbon emissions reduction than Case 1.

Figure 8.7.1 – WPL 2014 IRP Carbon Emission Rate for WPL Generating Resources



8.8 Conclusion

The primary conclusion of this 2014 IRP is that the addition of a generic 2:1 natural gas fired Combined Cycle (NGCC) unit is the best resource choice for the capacity and energy need beginning in 2019. It was chosen in the EGEAS model among a 1:1 NGCC, 1:0 CT, Wind, Solar, Biomass, Biogas, and Aggressive DSM, to satisfy identified capacity and energy needs. This resource selection was made in the base case and all of the sixteen sensitivities.

Appendix 2A

WPL Capacity and Energy Forecast Model Details

(*Does not contain confidential information*)

Appendix 2A

This appendix includes the following items:

- 2A.1 Model detail;
- 2A.2 Model changes; and
- 2A.3 Forecast as compared to prior filing.

2A.1 WPL Forecast Model Details

2A.1.1. *WPL Residential Sales*

WPL forecasts monthly residential sales based on the following multivariate regression model of residential use per meter. Table 2A.1.1 shows the results of the WPL Residential model.

Table 2A.1.1
WPL Residential Sales Model Parameters

The REG Procedure

Model: MODEL1
Dependent Variable: Res_UPC Res_UPC

Number of Observations Read	192
Number of Observations Used	128
Number of Observations with Missing Values	64

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	14	1.88143	0.13439	77.69	<.0001
Error	113	0.19546	0.00173		
Corrected Total	127	2.07688			

Root MSE	0.04159	R-Square	0.9059
Dependent Mean	0.72656	Adj R-Sq	0.8942
Coeff Var	5.72421		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.59092	0.05269	11.22	<.0001
Feb	Feb	1	-0.13234	0.01909	-6.93	<.0001
Mar	Mar	1	-0.08653	0.02504	-3.46	0.0008
Apr	Apr	1	-0.10485	0.03667	-2.86	0.0051
May	May	1	-0.08441	0.04581	-1.84	0.0680
Jun	Jun	1	-0.03668	0.05313	-0.69	0.4913
Jul	Jul	1	0.08575	0.05659	1.52	0.1325
Aug	Aug	1	0.10475	0.05467	1.92	0.0579
Sep	Sep	1	-0.03764	0.04926	-0.76	0.4464
oct	oct	1	-0.09295	0.03874	-2.40	0.0181
Nov	Nov	1	-0.10965	0.02893	-3.79	0.0002
Dec	Dec	1	-0.01514	0.01900	-0.80	0.4273
MN_HDD	MN_HDD	1	0.00019797	0.00003664	5.40	<.0001
MN_CDD	MN_CDD	1	0.00094193	0.00009703	9.71	<.0001
Pre2009	Pre2009	1	0.01358	0.00750	1.81	0.0728

Where:

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.
- MN_HDD: Madison Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of the high and low temperature. This variable measures the impact of cold temperature on sales.
- MN_CDD: Madison Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.
- Pre2009: An indicator to account for higher use per customer leading up to and through 2009. This was used to account for changing economic conditions in the WPL service territory.

2A.1.2 WPL Commercial Sales

WPL forecasts monthly Commercial sales based on the following econometric model. Table 2A.1.2 shows the results of the WPL Commercial model.

Table 2A.1.2
WPL Commercial Sales Model Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: Com_sales Com_sales

Number of Observations Read	192
Number of Observations Used	128
Number of Observations with Missing Values	64

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	15	39587905778	2639193719	52.55	<.0001
Error	112	5625096956	50224080		
Corrected Total	127	45213002734			

Root MSE	7086.89495	R-Square	0.8756
Dependent Mean	187554	Adj R-Sq	0.8589
Coeff Var	3.77858		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	21636	34281	0.63	0.5292
Feb	Feb	1	-24175	3252.56236	-7.43	<.0001
Mar	Mar	1	-10191	4267.16678	-2.39	0.0186
Apr	Apr	1	-21746	6250.44003	-3.48	0.0007
May	May	1	-6582.88802	7807.14092	-0.84	0.4009
Jun	Jun	1	-1428.49557	9053.81874	-0.16	0.8749
Jul	Jul	1	14030	9648.64407	1.45	0.1487
Aug	Aug	1	12681	9317.45945	1.36	0.1762
Sep	Sep	1	-34.86239	8395.29877	-0.00	0.9967
oct	oct	1	-7607.97635	6605.75835	-1.15	0.2519
Nov	Nov	1	-21061	4935.53374	-4.27	<.0001
Dec	Dec	1	-3226.28287	3250.55137	-0.99	0.3231
MN_HDD	MN_HDD	1	14.22714	6.24417	2.28	0.0246
MN_CDD	MN_CDD	1	109.85349	16.71164	6.57	<.0001
Pre2009	Pre2009	1	4259.58369	2211.92447	1.93	0.0567
Com_meter	Com_meter	1	2.82800	0.59149	4.78	<.0001

Where:

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.

- MN_HDD: Madison Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of the high and low temperature. This variable measures the impact of cold temperature on sales.
- MN_CDD: Madison Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.
- Pre_2009: An indicator to account for higher use per customer leading up to and through 2009. This was used to account for changing economic conditions in the WPL service territory.
- Com_meter: The number of commercial meters for each month in the data series. This variable corrects for any month to month changes in the number of commercial meters.

2A.1.3 WPL Industrial Sales

WPL forecasts monthly Industrial sales using the following econometric model of use per meter. Table 2A.1.3 shows the WPL Industrial model results.

Table 2A.1.3
WPL Industrial Sales Model Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: Ind_sales Ind_sales

Number of Observations Read	192
Number of Observations Used	128
Number of Observations with Missing Values	64

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	13	62885246730	4837326672	18.00	<.0001
Error	114	30632902134	268709668		
Corrected Total	127	93518148865			

Root MSE	16392	R-Square	0.6724
Dependent Mean	260141	Adj R-Sq	0.6351
Coeff Var	6.30133		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-74367	72651	-1.02	0.3082
Feb	Feb	1	7199.00503	6995.77276	1.03	0.3056
Mar	Mar	1	23433	6997.33604	3.35	0.0011
Apr	Apr	1	15750	6992.15972	2.25	0.0262
May	May	1	54976	6989.90467	7.87	<.0001
Jun	Jun	1	48778	6990.76794	6.98	<.0001
Jul	Jul	1	62283	6999.44860	8.90	<.0001
Aug	Aug	1	48471	7008.87191	6.92	<.0001
Sep	Sep	1	41877	7165.64685	5.84	<.0001
oct	oct	1	58806	7164.53979	8.21	<.0001
Nov	Nov	1	24724	7170.56767	3.45	0.0008
Dec	Dec	1	23196	7164.94691	3.24	0.0016
Ind_meter	Ind_meter	1	314.77381	78.00507	4.04	<.0001
Pre2009	Pre2009	1	9718.43552	3023.97819	3.21	0.0017

Where:

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.

- Ind_meter: The number of industrial meters for each month in the data series. This variable corrects for any month to month changes in the number of commercial meters.
- Pre_2009: An indicator to account for higher use per customer leading up to and through 2009. This was used to account for changing economic conditions in the WPL service territory.

2A.1.4 W*PL Summer Peak*

Table 2A.1.4 shows the model results.

Table 2A.1.4
Summer Peak Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: peak total

Number of Observations Read	1038
Number of Observations Used	920
Number of Observations with Missing Values	118

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	9	64508228	7167581	1201.52	<.0001
Error	910	5428538	5965.42681		
Corrected Total	919	69936766			

Root MSE	77.23618	R-Square	0.9224
Dependent Mean	1802.62091	Adj R-Sq	0.9216
Coeff Var	4.28466		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-26.79335	81.26098	-0.33	0.7417
Jul		1	79.22332	7.36215	10.76	<.0001
Aug		1	77.23779	7.22045	10.70	<.0001
Sep		1	15.55580	7.59914	2.05	0.0409
hot1	high-75	1	29.20513	0.75359	38.75	<.0001
Hot2	high-90	1	-6.20338	2.86794	-2.16	0.0308
hot3	low-60	1	9.62611	1.01711	9.46	<.0001
hot4	Max_Dew-50	1	5.25411	0.57088	9.20	<.0001
prehigh		1	4.96853	0.46593	10.66	<.0001
W_RPI		1	0.00583	0.00038090	15.29	<.0001

Where:

- Jul, Aug, Sep are monthly indicators.
- Hot 1 is the Daily High temperature less 75 degrees. This captures the impact of warm weather on loads. For temperatures over 90, this is a positive value that is partially offset by the Hot2 variable.
- Hot2 is the Daily High temperature less 90 degrees. The coefficient is negative because the predicted increase in load from the Hot1 variable is partially offset when the temperature is over 90 degrees. This allows for a different reaction to temperature under extreme heat.
- Hot3 is the overnight low less 60 degrees. Warmer overnight temperatures lead to higher loads.
- Hot4 is the highest daily dew point less 50 degrees. This variable captures the fact that higher dew points, and therefore higher humidity, lead to higher cooling loads.
- Prehigh is the high temperature on the previous day. Repetitive high temperature days lead to higher loads.
- W_RPI is the Wisconsin Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides. Higher income may also be indicative of increased commercial and industrial activity, which would translate to higher loads in those sectors.

2A1.5 WPL Annual Peak

Table 2A.1.5 shows the model results.

Table 2A.1.5
Annual Peak Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: dailypeak total

Number of Observations Read	41
Number of Observations Used	11
Number of Observations with Missing Values	30

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	3	205294	68431	20.18	0.0008
Error	7	23742	3391.77689		
Corrected Total	10	229036			

Root MSE	58.23896	R-Square	0.8963
Dependent Mean	2419.72774	Adj R-Sq	0.8519
Coeff Var	2.40684		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-80.01815	572.23638	-0.14	0.8927
hot1	avgtemp-70	1	16.68848	7.52024	2.22	0.0620
prhightmp		1	8.30733	5.62727	1.48	0.1834
W_RPI		1	0.00800	0.00328	2.44	0.0450

Where:

- Hot 1 is the Daily average temperature less 70 degrees. This captures the impact of warm weather on loads.
- Prhightmp is the high temperature on the previous day. Repetitive high temperature days lead to higher loads.
- W_RPI is the Wisconsin Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides.

2A.1.6 WPL Monthly Peak

Table 2A.1.6 shows the model results.

Table 2A.1.6
Monthly Peak Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: peak total

Number of Observations Read	486
Number of Observations Used	128
Number of Observations with Missing Values	358

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	14	11021118	787223	116.01	<.0001
Error	113	766823	6786.04110		
Corrected Total	127	11787940			

Root MSE	82.37743	R-Square	0.9349
Dependent Mean	1870.35334	Adj R-Sq	0.9269
Coeff Var	4.40438		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	508.80338	221.05332	2.30	0.0232
hdd		1	3.38452	1.05802	3.20	0.0018
cdd		1	38.14551	2.65056	14.39	<.0001
Feb		1	-47.94010	35.33012	-1.36	0.1775
Mar		1	-102.90504	38.92000	-2.64	0.0094
Apr		1	-172.87225	51.30872	-3.37	0.0010
May		1	-178.06463	71.11026	-2.50	0.0137
Jun		1	38.83774	77.88505	0.50	0.6190
Jul		1	125.79347	78.86059	1.60	0.1135
Aug		1	157.53491	78.03784	2.02	0.0459
Sep		1	86.23663	73.73384	1.17	0.2446
Oct		1	-64.07271	63.35163	-1.01	0.3140
Nov		1	-21.19710	43.03587	-0.49	0.6233
Dec		1	64.76986	36.64725	1.77	0.0799
W_RPI		1	0.00561	0.00107	5.25	<.0001

Where:

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec are monthly indicators that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in demand.
- hdd: Madison Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of

the high and low temperature. This variable measures the impact of cold temperature on sales.

- cdd: Madison Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.
- W_RPI is the Wisconsin Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides.

2A.2 Model Changes

WPL made the following improvements in the forecasting process in 2013.

- **Change to top-down regression modelling approach**. Previously, WPL forecasted sales for individual rate clases and then aggregated these amounts to arrive at sector-level and retail-level sales. The forecasts developed for this plan use a top-down approach. Sector-level models are used to forecast sales and then allocators are used distribute MWH to the various rate classes. WPL adopted this approach to increase consistency with other forecast methodology applied at the company.
- **Calendar month data**: Previously, WPL's energy forecast matched billed sales to a "calculated" corresponding monthly weather amount. The new process matches calendar month sales to calendar month weather, which reduces complexity in the modeling.
- **Consistent inputs**: In the prior plan, the number of years of historical data was not consistent between models. The current forecast uses ten years of historical data in all of the regression models.
- **Consensus Peak:** In the prior plan, WPL used recent trends in peak and weather-normalized peak to forecast the peak. In the current plan, WPL uses multiple models (annual, seasonal and monthly models) to determine a consensus forecast of the peak.
- **Coincident Peak:** WPL now forecasts a MISO coincident peak demand. Previously, WPL only forecasted non-coincident internal peak demand.
- **Forecast of Internal Demand:** Previously, WPL's forecasted peak demand excluded available (but not called) interruptible load. In the current model, WPL includes interruptible loads that might be called during peak times, creating a theoretical peak, which is used in the forecast models. This leads to fewer adjustments to the data.

2A.4 Comparison to prior Plan

See table 2A.4.2 for a comparison the energy forecasts used in the current and prior resource plans. Primarily, the forecasts for the two resource plans differ due to the lower assumed distribution and transmission losses and lower assumed long term growth rates in the 2014 resource plan. The transmission loss factor used in the 2012 resource plan was 3.0 percent, compared to 2.9 percent in the 2014 resource plan. The distribution loss factor used in the 2012 resource plan was 4.60 percent compared to 3.12 percent in the 2014 resource plan. A comparison of these loss factors is provided in table 2A.4.1, below.The assumed growth rate used in the long term energy forecast of the 2012 resource plan was 1.1 percent, compared to 0.7 percent in the 2014 resource plan. The different growth rates stem from multiple variables, including changes in forecasting processes, source data and changing economic outlooks.

Table 2A.4.1
Comparison of Loss Factors

Factor	2012 IRP	2014 IRP
Distribution	4.60%	3.12%
Transmission	3.00%	2.92%

Table 2A.4.3 compares the peak forecasts for the 2012 and 2014 resource plans. As with table 2A.4.2, updated distribution and transmission loss factors and lower assumed growth rates mostly account for the differences in the forecasts.

Table 2A.4.2
Comparison of Annual Energy (GWh)

Year	2014 IRP	2012 IRP*	Variance	Percent
2012	NA	12,748	NA	NA
2013	NA	12,820	NA	NA
2014	12,632	13,020	(388)	-3%
2015	12,808	13,150	(342)	-3%
2016	13,008	13,276	(268)	-2%
2017	13,085	13,405	(320)	-2%
2018	13,184	13,547	(363)	-3%
2019	13,274	13,691	(417)	-3%
2020	13,372	13,837	(465)	-3%
2021	13,472	13,984	(512)	-4%
2022	13,571	14,134	(563)	-4%
2023	13,672	14,286	(614)	-4%
2024	13,774	14,440	(666)	-5%
2025	13,876	14,595	(719)	-5%
2026	13,979	14,754	(775)	-5%
2027	14,082	14,914	(832)	-6%
2028	14,187	15,077	(890)	-6%
2029	14,292	15,241	(949)	-6%
2030	14,398	15,407	(1,009)	-7%
2031	14,505	15,576	(1,071)	-7%
2032	14,612	15,746	(1,134)	-7%
2033	14,721	15,918	(1,197)	-8%
2034	14,830	16,092	(1,262)	-8%
2035	14,940	16,268	(1,328)	-8%
2036	15,051	16,445	(1,394)	-8%
2037	15,162	16,625	(1,463)	-9%
2038	15,274	16,807	(1,533)	-9%
2039	15,388	16,990	(1,602)	-9%
2040	15,502	17,175	(1,673)	-10%
2041	15,617	NA	NA	NA
2042	15,732	NA	NA	NA

See Table 2A.4.3 for a comparison of the Peak forecasts between the current and prior plan.

Table 2A.4.3
Comparison of Internal Demand (MW)

Year	2014 IRP	2012 IRP*	Variance	Percent
2012	NA	2,664	NA	NA
2013	NA	2,678	NA	NA
2014	2,548	2,710	(162)	-6%
2015	2,585	2,728	(143)	-6%
2016	2,619	2,745	(126)	-5%
2017	2,634	2,746	(111)	-4%
2018	2,654	2,774	(120)	-5%
2019	2,672	2,802	(130)	-5%
2020	2,692	2,831	(140)	-5%
2021	2,712	2,861	(149)	-5%
2022	2,732	2,891	(159)	-6%
2023	2,752	2,921	(169)	-6%
2024	2,773	2,952	(179)	-6%
2025	2,793	2,983	(190)	-7%
2026	2,814	3,014	(201)	-7%
2027	2,834	3,046	(212)	-7%
2028	2,855	3,078	(223)	-8%
2029	2,876	3,111	(235)	-8%
2030	2,897	3,144	(247)	-9%
2031	2,919	3,178	(259)	-9%
2032	2,940	3,212	(272)	-9%
2033	2,962	3,246	(284)	-10%
2034	2,984	3,281	(297)	-10%
2035	3,006	3,316	(310)	-10%
2036	3,028	3,351	(324)	-11%
2037	3,050	3,387	(337)	-11%
2038	3,073	3,423	(351)	-11%
2039	3,095	3,460	(365)	-12%
2040	3,118	3,497	(379)	-12%
2041	3,141	NA	NA	NA
2042	3,164	NA	NA	NA

Appendix 3A

Demand Side Management

(*Confidential information is marked gray*)

Table 3.3.2 WPL 2014 IRP EGEAS Detailed Cost Development for Abbreviated Unit Name DDSM P 2016-2020				
Development of Aggressive Wisconsin and WPL DSM Costs and Energy and Demand Savings				
Average of Iowa and Minnesota Percent of Statewide Utility Revenues Spent on DSM to calculate an Aggressive Wisconsin Level of DSM				
	Energy Efficiency Budget by State	**Percent of Total Operating Revenue**	**Percent of Energy Sold (MWH)**	
	Iowa	2.560%	1.040%	
	Minnesota	2.600%	1.210%	
	Average	2.580%	1.125%	
Source, Tables 11 and 14 in "The 2013 State Energy Efficiency Scorecard" hyperlink at:				
http://www.truevaluemetrics.org/DBpdfs/Metrics/ACEEE/ACEEE-2013-State-Energy-Efficiency-Scorecard.pdf				
Wisconsin 2012				
		Revenue	**Energy (MWH)**	
	Total Sales to Ultimate Customers	$ 1,033,620,011	10,348,913	
	Less Interdepartmental Sales	$ 1,475,934	23,535	
	Retail Sales 2012	$ 1,032,144,077	10,325,378	
	Minnesota and Iowa Percent (from above)	2.580%	1.125%	
Development of Aggressive Wisconsin DSM to Match the Average of MN & IA Percent of Statewide Utility Revenues Spent on DSM				
		Development of Program Cost	**Development of first year annual end-use energy savings (MWH)**	**Development of first year annual End-Use Demand / Capacity Savings (MW)**
	Attribution Rate		100%	
	(reported energy savings credited to program - i.e. net-to-gross assumption)			
	WPL results to match average MN & IA DSM	$ 26,629,317	116,161	
	Focus on Energy statewide net energy savings in 2012		460,785	
	WPL Average Operating Revenue as a Percent of the State Total FOE Budget *		16.8%	
	Less Focus on Energy - Electric	$ 14,152,367	77,412	
	Less Customer Support	$ 1,329,800		
INCREMENTAL DSM TO BRING WISCONSIN UP TO MINNESOTA AND IOWA AVERAGE		$ 11,147,150	38,749	
Load Factor				0.65
Demand / Capacity Savings				6.8
***the percentage, 16.8%, is arrived at by taking WPL's 3 year operating revenue (2009,2010,2011) as reported to the PSC $16,649,997 divided**				
by the state total for Focus on Energy budget $98,923,287.				

Table 3.3.2 WPL 2014 IRP EGEAS Detailed Cost Development for Abbreviated Unit Name DDSM P 2016-2020				
Wisconsin 2013	USES 2012 INFORMATION TO ESTIMATE - 2013 NOT AVAILABLE YET			
	Total Sales to Ultimate Customers	$ 1,197,200,000	10,364,000	
	Less Interdepartmental Sales	$ 1,475,934	23,535	
	Retail Sales 2013	$ 1,195,724,066	10,340,465	
	Minnesota and Iowa Percent (from above)	2.580%	1.125%	
Development of Aggressive Wisconsin DSM to Match the Average of MN & IA Percent of Statewide Utility Revenues Spent on DSM				
		Development of Program Cost	**Development of first year annual end-use energy savings (MWH)**	**Development of first year annual End-Use Demand / Capacity Savings (MW)**
	Attribution Rate		100%	
	(reported energy savings credited to program - i.e. net-to-gross assumption)			
	WPL results to match MN & IA DSM	$ 30,849,681	116,330	
	Focus on Energy statewide net energy savings in 2012		460,785	
	WPL Average Operating Revenue as a Percent of the State Total FOE Budget **		16.8%	
	Less Focus on Energy - Electric	$ 14,152,367	77,412	
	Less Customer Support	$ 1,329,800		
INCREMENTAL DSM TO BRING WISCONSIN UP TO MINNESOTA AND IOWA AVERAGE		$ 15,367,514	38,918	
Load Factor				0.65
Demand / Capacity Savings				6.8
****The percentage, 16.8%, is arrived at by taking WPL's 3 year operating revenue (2009,2010,2011) as reported to the PSC $16,649,997 divided**				
by the state total for Focus on Energy budget $98,923,287.				
Further Information				
First Year Demand Saved or Savings				
Focus on Energy is Wisconsin utilities' statewide energy efficiency and renewable resource program.				
Since 2001, the program has worked with eligible Wisconsin residents and businesses to install cost-effective energy efficiency and renewable energy projects.				
The information, resources and financial incentives we provide help to implement energy saving projects that otherwise would not be completed, or to complete				
projects sooner than scheduled.				
These energy projects:				
Help Wisconsin residents and businesses manage rising energy costs				
Promote in-state economic development				
Protect our environment				
Control Wisconsin's growing demand for electricity and natural gas				
Focus on Energy is funded by the state's investor-owned energy utilities, as required under Wis. Stat. § 196.374(2)(a), and participating municipal and electric				
cooperative utilities.				
To participate in Focus on Energy programs, residents or business owners must be customers of a participating utility.				
Attribution rate is defined as actual savings attributed to program (a net result of energy saving attributed to program).				

Table 3.3.3 WPL 2014 IRP EGEAS Detailed Cost Development for Aggressive DSM, EGEAS Abbreviated Unit Name DDSM P 2016-2020
EGEAS Implementation of Aggressive Wisconsin DSM Costs and Energy and Demand Savings
Confidential data is hugh-lighted in gray.

						2016 Model Year	"Incremental DSM to match MN & IA - highest in Midwest				
	Aggressive DSM Dollars Spending to Match MN & IA	Aggressive / Incremental DSM Energy to Match MN & IA	First Year Annual Energy Saved at Generator 6.04%	Aggressive / Incremental DSM Demand to Match MN & IA	First Year Annual Capacity Saved at Generator 7.27%	5 year aggressive plan	Wood Mackenzie, **CPI** "NAGS_LTV_Price_Outlook_Oct_2011.xls"	Inflator Factor from 2010 base	Estimated Cost for Incremental Program	Energy Avoided Aggressive DSM [at Generator]	Demand Avoided Aggressive (at Generator) DSM
Year			1.0604		1.0727					Levelized	
	$	MWH	MWH	MW	MW		[redacted]		DSM $	MWH	MW
2016	$ 15,367,514	38,918	41,269	6.8	7.3	2016			$15,674,864	41,269	7.3
2017	$ 15,367,514	38,918	41,269	6.8	7.3	2017			$15,988,362	82,537	14.6
2018	$ 15,367,514	38,918	41,269	6.8	7.3	2018			$16,308,129	123,806	21.9
2019	$ 15,367,514	38,918	41,269	6.8	7.3	2019			$16,634,291	165,075	29.2
2020	$ 15,367,514	38,918	41,269	6.8	7.3	2020			$16,966,977	206,343	36.5
2021	$ -	-	-	0	-	2021			$0	206,343	36.5
2022						2022			$0	206,343	36.5
2023						2023			$0	206,343	36.5
2024						2024			$0	206,343	36.5
2025						2025			$0	206,343	36.5
2026						2026			$0	206,343	36.5
2027						2027			$0	206,343	36.5
2028						2028			$0	165,075	29.2
2029						2029			$0	123,806	21.9
2030						2030			$0	82,537	14.6
2031						2031			$0	41,269	7.3
2032						2032			$0	0	-
2033						2033			$0	0	-
2034						2034			$0	0	-
2035						2035			$0	0	-
2036						2036			$0	0	-
2037						2037			$0	0	-
2038						2038			$0	0	-
2039						2039			$0	0	-

6.04% and 7.27% are the distribution and transmission losses for energy and peak

Modeled Values (entered by EMN)			
	Rated & Reserve Capacity	Energy Limit (GWh)	Program cost modeled in Detailed Cost as Fixed O&M
Year	MW	GWh	$/kW-yr.
2016	7.3	41.3	2,148.9
2017	14.6	82.5	1,095.9
2018	21.9	123.8	745.2
2019	29.2	165.1	570.1
2020	36.5	206.3	465.2
2021	36.5	206.3	-
2022	36.5	206.3	
2023	36.5	206.3	
2024	36.5	206.3	
2025	36.5	206.3	
2026	36.5	206.3	
2027	36.5	206.3	
2028	29.2	165.1	
2029	21.9	123.8	
2030	14.6	82.5	
2031	7.3	41.3	
2032	-	-	

Percent Losses		
Loss Level	**Energy**	**Demand**
Distribution	**3.12**	**4.40**
Plus Transmission	**2.92**	**2.87**
Total	6.04	7.27

Source: P&E 2013 MRO dated 10/30/2013

MODEL INPUTS Base year and multipliers			
	Rated & Reserve Capacity	Energy Limit (GWh)	Program cost modeled in Detailed Cost as Fixed O&M
BASE Values	7.3	41.3	2,148.9
Year			
2012	0	0	-
2013	0	0	-
2014	0	0	-
2015	0	0	-
2016	1.00	1.00	1.0000
2017	2.00	2.00	0.5100
2018	3.00	3.00	0.3468
2019	4.00	4.00	0.2653
2020	5.00	5.00	0.22
2021	5.00	5.00	-
2022	5.00	5.00	-
2023	5.00	5.00	-
2024	5.00	5.00	-
2025	5.00	5.00	-
2026	5.00	5.00	-
2027	5.00	5.00	-
2028	4.00	4.00	-
2029	3.00	3.00	-
2030	2.00	2.00	-
2031	1.00	1.00	-
2032	-	-	-

Appendix 4A

Distributed Generation Study

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Wisconsin Power & Light

Distributed Generation Market Forecast

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Acronyms

AC	Alternating current
ART	Advanced renewable tariff
BTU	British thermal unit
CHP	Combined heat and power
CP-1	Electricity tariff for industrial power at primary or secondary voltage
CPUC	California Public Utilities Commission
DC	Direct current
DG	Distributed generation
DR	Demand response
EIA AEO	Energy Information Administration Annual Energy Outlook
ELCC	Effective load carrying capacity
EOY	End of year
EPRI	Electric Power Research Institute
GS	General service electricity tariff
HHV	Higher heating value
HP	High pressure
ICE	Internal combustion engine
ITC	Investment tax credit
kW/m2	Kilowatts per square meter
kW	Kilowatt
kWe	Kilowatt electrical
kWh	Kilowatt hour
LACE	Levelized avoided cost of electricity
lb/MMBtu	Pounds per million British thermal units
LCOE	Levelized cost of energy
LHV	Lower heating value
LMOP	Landfill Methane Outreach Program
LP	Low pressure
LVOE	Levelized value of energy
MACRS	Modified accelerated cost recovery system
mBtu/kWh	Thousands of British thermal units per kilowatt hour
MISO	Midcontinent Independent System Operator
mmBtu/H	Millions of British thermal units per hour
mmBtu/yr	Millions of British thermal units per year

MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt hour
NG CHP	Natural gas combined heat and power
NO_x	Nitrogen oxides
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PG	Parallel generation
PSIG	Pounds per square inch gauge
PTC	Production tax credit
PV	Photovoltaic
REAP	Rural Energy for America Program
SCR	Selective catalytic reduction
SWCC	Small Wind Certification Council
US EPA	United States Environmental Protection Agency
USDA	United States Department of Agriculture
WACC	Weighted average cost of capital
WPL	Wisconsin Power and Light
WPSC	Wisconsin Public Service Corporation
WWTP	Wastewater Treatment Plant

1. INTRODUCTION

Alliant Energy retained Tech, Inc. (Tetra Tech) to provide a market forecast for distributed generation in the Wisconsin Power & Light (WPL) service territory for the 2014–2029 time period. This report describes the technologies considered, model development, and results of the research and modeling conducted by Tetra Tech. The forecast covers major distributed generation technology markets already in place in the WPL territory or the US in general. These technologies were modeled as customer-sited or wholesale distributed generation systems of a scale smaller than is typically considered by a utility for its own central power station investments. Although distributed generation makes up a small segment of the electricity generation market, it is a segment growing faster than the general US electricity market.

The forecast presents three scenarios covering the 2014–2029 time period. The three scenarios were developed to capture high, medium (base case), and low adoption rates. As the energy policy environment significantly influences the market for distributed generation technologies, these scenarios were developed to recognize the potential influences of those policies on distributed generation adoption.

The results of the forecast are based on estimates of market adoption rates for each technology and can be used by WPL for estimating customer electricity loads net of distributed generation or for planning generation resources and market-based supply. The forecasts are not meant to capture the maximum technical potential of distributed generation or maximum or minimum market potential adoption rates. The drivers of distributed generation investments are diverse and driven by technology cost trends, electricity prices experienced by investors to drive investment returns, capital availability within markets to drive investments, and state, local, and federal policies.

In this report we present the summary findings and conclusions along with the key policy considerations and data sources used to derive the forecasts. The methodology for each technology and detailed technology modeling results are presented in separate technology-focused sections.

Below we document the technologies included in this study. These technologies are present or exhibiting growth in the WPL service territory:

- Solar photovoltaics
- Wind energy systems
- Biogas from animal waste and wastewater treatment plants
- Landfill gas systems
- Combined heat and power options.

The forecast targeted these technologies as a means of addressing the aggregate distributed generation planning forecast. The size ranges considered were meant to allow for analyzing aggregate market effects that drive adoptions, rather than specific applications or configurations of the technologies. Specific customer or technology applications cannot be forecasted. Thus, the forecast results and technology selection should not be viewed as making a claim that no other potential technologies or specific situations may lead to additional or substitutive adoptions of distributed generation. Furthermore, the forecast's reliance on distributed generation economics to drive market adoptions assumes cost trends for distributed generation technology and utility supplied energy emerge. While the forecast presents market decisions leading to distributed generation adoption, they are not based on inevitabilities. The forecasts are predicated on distributed generation technologies becoming more cost effective and customer decision making responding to improved economics by choosing to adopt greater levels of distributed generation than currently deployed.

2. EXECUTIVE SUMMARY

As of the end of 2013, WPL has approximately 69 MW of interconnected distributed generation capacity.[1]

Table 2-1. Technology Contributions of Distributed Generation Capacity (<10 MW)

Technology	Total DG kW	Percent of WPL DG Capacity	Percent of NonHydro or NonDR DG Capacity
Wind	919	1.3%	3.1%
Demand response	13,800	19.9%	
Hydro	26,037	37.6%	
Solar photovoltaic	4,693	6.8%	16.0%
Combined heat & power	7,521	10.9%	25.6%
Farm biogas	3,768	5.4%	12.8%
Landfill biogas	9,235	13.3%	31.4%
WWTP biogas	3,233	4.7%	11.0%
Total	69,206	100%	
Total nonhydro or demand response	29,369	42%	100%

Since the 1970s, this distributed generation capacity has shifted its technology emphasis. Larger hydroelectric plants (over 1,000 kW) were all indicated as having been installed in the 1970s and 1980s, while a number of smaller hydroelectric systems were installed in the 1990s. Landfill gas projects were installed in the 1990s and 2000s. Since the mid-2000s, WPL distributed generation interconnections have been driven by biogas, wind, and solar electric systems.

The technology focus for WPL's distributed generation forecast does not include hydroelectric technology and focuses on systems that would generally be installed with less than 10 MW in capacity. Hydroelectric technology has seen no recent adoptions, and with permitting challenges and site-specific knowledge needed to determine technology potential, the hydroelectric market is not included for the forecast. Demand response resources are not included due to their sporadic utilization and ability for a utility to drive demand through a specific program. As the forecast is based on market adoptions, utility owned or developed systems are not included. The remaining technologies—wind, solar, biogas, and combined heat and power—reflect technologies with broad market application that have shown broad market adoptions in recent years in the WPL territory or in the US in general.

The forecast for distributed generation technologies in WPL's territory is based on three scenarios that reflect drivers in policy that could enhance or inhibit greater adoption. A base-case is framed by the current policy status as defined by net metering, retail rates, parallel generation tariffs, wholesale energy price forecasts, and federal incentives. For solar electric,

[1] Based on data from WPL; excludes customers with generating capacity 10 MW and larger.

wind energy, and biogas technology, the base case is defined by the expected sunset of the federal investment tax credit (ITC) or recently sunsetted production tax credits. These tax credits have provided significant capital cost reductions or enhanced the value of energy production to many distributed generation technologies and installations. For some technologies, such as MW-class wind and biogas, the tax credits available through the federal production tax credit (PTC) or ITC conversion have expired and a low-policy support case already exists. For solar and wind energy systems 100 kW and less, the ITC offers a 30 percent tax credit, set to expire Dec 31, 2016. After 2016, solar electric technologies will still be able to leverage a 10 percent ITC, while wind energy systems will not receive any federal incentives.

For the high-policy case, the scenario is defined by two policy options, applied to different technologies. For net metered solar electric and customer-sited wind (20 kW and less), the high-policy scenario assumes the federal ITC is extended indefinitely. The Energy Information Administration (EIA) modeling is used to consider the impact of an ongoing ITC for these technologies. In the case of MW-class wind, biogas, landfill gas, and combined heat and power technologies, the high-policy case assumes generalized incentives that reduce capital costs, improving the investment environment for these technologies, with customers assumed to respond to improving economics of investment-grade technologies[2]. Thus, there are two core adoption models—one in which net metered systems rely on EIA forecasts of an extended tax credit and one that models the underlying economics of the technologies to forecast adoptions based on cost-effective investment decisions.

The low-policy case considers the effect of reduced financial benefit on market adoptions. For net metered solar and wind systems, the low-policy case is defined by possible changes to net metering that would reduce the value of these technologies. Specifically, it uses the effect of shifting from an annual net metering true-up to a monthly net metering true-up, similar to a policy shift experienced by Wisconsin Public Service Corporation net metering customers in the 2012 timeframe. In the case of investment-grade distributed generation, the forecasts differ by technology and the resulting relationship with retail, parallel generation, and wholesale price forecasts.

Below, we present the aggregate model results for each scenario. Subsequent sections for each technology provide additional detail for their respective technologies. The results show the incremental additional capacity through the forecast period at the distribution system level. The results exclude existing distributed generation system contributions.

[2] The use of the term "investment grade" distributed generation is not meant to imply that solar electric or small/medium wind market adoptions are not done for non-financial reasons. The differentiation is meant to capture the broader perspectives on historic adoptions that are often not driven primarily by financial returns. It also segments the distributed generation market that is influenced by the federal ITC compared to the expired PTC.

Table 2-2. Cumulative Additional Distributed Generation Capacity, WPL, 2014–2029

Year	Gross MW[3]			Summer Peak MW			Associated MWh		
Scenario	Base	High	Low	Base	High	Low	Base	High	Low
2014	0.15	0.15	0.15	0.05	0.05	0.05	186	186	186
2015	0.32	2.22	0.32	0.11	1.82	0.11	384	7,784	384
2017	0.51	8.36	0.50	0.17	6.14	0.16	917	30,097	599
2020	5.10	22.88	0.52	4.25	15.12	0.17	14,594	83,706	625
2025	18.63	61.47	6.55	14.89	40.13	4.39	63,595	217,599	18,359
2029	41.94	101.54	23.28	29.47	65.67	16.03	147,464	348,890	75,182

In the base case scenario, distributed generation capacity grows modestly in the early years of the forecast but accelerates in later years. The chief driver of base case capacity and energy growth through 2029 is combined heat and power adoptions. However, solar electric capacity also grows significant in the later years of the forecast, with systems over 20 kW (the current net metering limit) driving the growth in solar electric technology. Biogas capacity grows only through the addition of two small wastewater treatment projects. Wind technology offers very minor capacity and energy additions to the total distributed generation market.

In the low-policy scenario, distributed generation capacity is adopted at a much slower rate, though still dominated by combined heat and power. Solar electric technology over 20 kW shows strong growth in the second half of the forecast period as prices are estimated to drop and allow for cost-effective additions despite a low-policy support environment. Wind energy provides a very small amount of additional customer-sited turbines, with MW-class turbines showing no capacity additions. Biogas remains as in the base case, with only the wastewater treatment plant additions and no farm biogas added.

The high-policy case exhibits a much more robust distributed generation market. Solar electric and combined heat and power technologies dominate the forecast as policy effects are modeled to drive down system costs. Adoptions, based on project economics, occur earlier in the forecast with greater cumulative effects. Farm biogas dominates the biogas sector and MW-class wind is expected to offer substantially greater capacity than in the other two cases.

Regardless of the scenario, our forecast shows relatively modest effects on overall electricity loads. In the high-policy case, distributed generation is expected to equal only about 3.4 percent of WPL's 2012 retail electricity load. During the forecast period, many technologies are expected to become cost effective, from the perspective of investors in distributed generation systems. Despite the apparent cost effectiveness and substantial technical potential for distributed generation, capital and labor availability—along with development timelines, market momentum, and competition from non-energy investment options—will limit potential growth. That said, there a number of potential energy policy mechanisms that could drive growth rates higher than forecasted in this study. The high-policy scenario should not be viewed as a maximum potential, but rather a potential that could be achieved with modest

[3] For solar electric technology, gross MW is included on a DC basis. For solar electric MWh and Summer Peak MW, and for all other technologies, results are in AC.

additional policies that have been present in the recent past and without a major shift in approaches to energy development.

3. SCENARIO DESCRIPTIONS

3.1 INTRODUCTION

Three scenarios were developed to model the base case, high adoption, and low adoption rates for distributed generation. The three scenarios are based on the theory that policy is a major driver of distributed generation systems and will have a significant influence on market adoption. The base case assumes existing known policy continues as stipulated. The high adoption scenario, “higher policy case,” is based on an effect of key policies continuing or being implemented. The low adoption scenario is based on a “lower policy case” in which changes in policy drive down adoptions from the base case. Below we describe each scenario and the policy considerations used to develop that scenario.

The policy framework for the scenarios segment distributed generation into two groupings:

1) Net-metered systems:
   a. Solar electric 20 kW and less
   b. Wind energy 20 kW and less
2) Larger distributed generation systems typically installed primarily as an investment. These are:
   a. Solar and wind energy between 20 kW and 100 kW
   b. MW-class wind
   c. Solar 100 kW and larger
   d. Landfill gas
   e. Biogas
   f. Combined heat and power.

The net-metered systems exhibit large numbers of systems, though of relatively small kW capacities for each installation. To a degree, they are commodity products. Through 2016, the forecasts for these systems are based on recent market adoptions in the WPL territory, at which point the estimates leverage Energy Information Administration forecasts for long-term projections after 2016. In contrast, the larger distributed generation systems are modeled based on a levelized cost of energy compared to a forecasted estimate of the relevant mix of retail, wholesale, parallel generation, and natural gas prices to determine cost effectiveness through the forecast period.

Below we describe each of the three scenarios and policy considerations that drive the forecasted market adoptions for each scenario.

3.2 BASE CASE SCENARIO

The base case scenario assumes the federal investment tax credit (ITC), currently set to expire at the end of 2016, will not be extended further and will expire on December 31, 2016. The ITC, which provides a 30 percent tax credit for solar electric and wind systems 100 kW and less, among other distributed generation technologies, has played an important role in reducing capital costs for adopters of distributed generation technologies. Upon expiration of the credit, solar electric systems installed after 2016 will be eligible to receive a 10 percent tax credit. Small wind systems will receive no tax credit after 2016.

Under this scenario, the years after 2016, for which the ITC will drop from its 30 percent value, were modeled separately from the years leading up to 2017. Specifically, for the period of 2014–2016, growth rates of net metered solar and wind systems were forecast using information about existing installations and capacity growth between 2008 and 2013. Upon expiration of the 30 percent ITC (December 31, 2016), the cumulative growth rate of non-marketed solar electric systems provided in the reference case of the EIA 2013 Annual Energy Outlook was used to estimate growth of solar electric technologies in WPL’s territory. For net metered wind systems, the cumulative growth rate is assumed to be half that of solar electric systems, reflecting price competition and relative ease of solar electric installation and operations compared to small wind systems.

In the case of all non-net metered technologies, a cost-effectiveness model was used to estimate when and if a technology would be cost effective during the forecast period. This cost effectiveness model was coupled to an estimate of capital availability based on 2008–2013 adoptions for either WPL specifically or using state-wide adoptions if WPL data did not exhibit a pattern. For example, wind systems over 20 kW and up to 100 kW have been installed in the WPL territory, lending this technology to a WPL-specific adoption rate. However, in the case of MW-class wind, no distributed systems have been developed in the WPL territory, though installations have occurred in other parts of Wisconsin, lending itself to a state-level adoption rate.

For the models using cost effectiveness as a core component driving the forecast model, the levelized cost of energy for each technology was calculated, allowing for a comparison of the cost of energy to the relevant market rate. In some cases this rate is the retail rate, in others the parallel generation tariff, or a blend of retail and parallel generation tariffs. On-peak and off-peak rate differences were applied to create a blend based on each technology’s expected alignment to WPL’s on-peak and off-peak times. All net present value calculations used the weighted average cost of capital provided by WPL (7.77 percent). The specifics for each technology are described in each technology section of the report.

3.3 HIGH-POLICY SCENARIO

The high-policy scenario, leading to greater distributed generation adoption, is based on a logic similar to the base case. For net metered solar and wind systems (20 kW and less), the “No Sunset” case in EIA’s 2013 Annual Energy Outlook cumulative growth rates are used to drive adoptions. The EIA’s “No Sunset” case presents the EIA’s estimate of the effect of extending the federal ITC indefinitely beyond 2016. Our forecast assumes that the EIA’s national model for cumulative growth rates can reasonably be applied to WPL. However, for the years prior to 2017, growth rates of net metered solar and wind systems were estimated using growth rate information from WPL for 2008 through 2013. Only after 2016 were the EIA’s “No Sunset Case” annual growth rates for non-marketed solar photovoltaic systems used for the remainder of the forecasting period. For net metered wind systems the EIA’s solar growth rate was halved, reflecting likely competition from solar electric systems and what has been historically lower growth.

For systems with capacities that exceed net metering limits, an economic model was employed. The base case economics were adjusted to allow for policy interventions to drive down the capital costs of these systems. For some technologies, this was modeled based on an extension of the federal ITC (solar electric and wind systems between 20 kW and 100 kW). In other cases, an assumed net effect of policies was used to drive down system costs based on a range of 25 to 35 percent, reflecting varying policy approaches to each technology.

The base case assumptions regarding energy costs were maintained. As with the base case, the high-policy case uses an assumption that capital availability drives the potential capacity additions each year, with cost effectiveness triggering whether additional capacity would be installed. The overall effect of the capital availability assumptions are to advance the point in time for the larger distributed generation systems to be “investment worthy,” resulting in greater cumulative impact.

Beyond the economic model and capital availability assumptions, the high-policy case also exhibited a shift in technology spending. The economic model revealed that in the last three years of the forecast, large solar systems (over 100 kW) would be more cost effective than MW-class wind systems, though both would be cost effective. The high-policy case models 50 percent of the capital expenditures that would have gone to MW-class wind system investments being used for large solar installations in these three years. This is the single instance in which the modeling explicitly accounted for a level of technology substitution, though it is possible for any of the modeled technologies that some level of substitution could occur.

3.4 LOW-POLICY SCENARIO

The low-policy scenario assumes an environment that makes investment in distributed generation technologies less attractive. Examples of what could be in a low-policy support environment include shifting to monthly net metering true-ups over the traditional annual true-ups or applying wholesale rates to exported energy as opposed to parallel generation tariffs. For net metered systems, our model takes these types of distributed generation policies into account by reducing the EIA reference case growth rate by 75 percent for solar and wind systems less than 20 kW. As shown in Table 3-1, this decrease is in line with an annualized estimate of the reduction witnessed by Wisconsin Public Service Corporation between 2011 and 2013, a period during which a two-tiered net metering structure coupled with monthly netting was enacted, along with a significant reduction and cancellation of Focus on Energy renewable energy incentives.

Table 3-1. Interconnection Requests Made to WPSC by Year[4]

Year	Residential	Commercial/Industrial	Total
2011	52	26	78
2012	32	6	38
2013[5]	12	6	18
Decrease (2011–2013)	76.9%	76.9%	76.9%

[4] “Wisconsin Public Service Corporation, Docket 6690-UR-122 (PSC Ref# 190934).
[5] 2013 numbers are estimated using prorated year-to-date (through August 2013) data.

As in the base case scenario, growth rates of net metered solar and small wind turbines in Wisconsin were estimated using growth rate information from WPL for 2008 through 2013, applied to 2014–2016 to reflect the presence of the federal ITC. For those years, there is no distinction between the base case and low-policy case for net metered systems. For the remaining years in our estimation we used the EIA's "reference case" non-marketed solar photovoltaic annual growth rates, reduced by 75 percent. For small wind systems, that growth rate is halved to account for competition from solar photovoltaics.

For systems over the 20 kW net metering threshold, the underlying economic model is used to estimate adoptions. For power exported to the grid, wholesale electricity prices are substituted for parallel generation tariffs. However, retail offsets, in which customers are able to substitute their retail electricity purchases with electricity from distributed generation, remain the same value as other scenarios. In the case of combined heat and power, which assumes 100 percent retail offset, the potential adoption rate is halved from the base case, with capacity additions delayed during the forecast period. For nearly all the non-net metered technologies, the low-policy case either makes the technologies not cost effective or significantly delays the timing and cumulative impact of distributed generation additions.

3.5 ECONOMIC MODELING

With the exception of distributed generation capacity sizes expected to operate in a net metering or similar context (20 kW or less), Tetra Tech employed an economic model to help estimate the likelihood of adoption during the forecast period. The economic model was applied to each technology for each year of the forecast period to arrive at a Levelized Cost of Energy (LCOE) and Levelized Value of Energy (LVOE). A year was deemed as having high potential for adoption if a given technology's LCOE was less than its corresponding LVOE in that year. Below we describe the LCOE and LVOE methodologies and key assumptions for each technology considered for the study.

A. Levelized cost of energy

The National Renewable Energy Laboratory (NREL) defines levelized cost of energy as "the cost of generating energy for a particular system."[6] The LCOE incorporates all capital and operation costs, and may include financial benefits such as tax credits, depending on the particular analysis being performed. The LCOE reflects the net present value expressed in terms of cost per unit of energy (e.g., $ per MWh) required for a break-even investment decision over the life of an energy project. An LCOE can be used to compare technology options with different costs, lifespans, and capacity factors, or to a decision to *not* invest in a technology on a lifecycle basis.

Key input variables into the levelized cost calculation used for the WPL distributed generation forecast include:

- Capital cost
- Operations and maintenance ($/kW-yr), exclusive of natural gas costs
- Net present value of natural gas costs (CHP only)

[6] http://www.nrel.gov/analysis/tech_lcoe_documentation.html.

- Net present value of avoided customer demand charges (if applicable)
- Net present value of MACRS depreciation
- Project useful life.

B. Levelized value of energy

The levelized value of energy is used in the WPL distributed generation forecast to estimate the value of energy over the life of an energy project started in a given forecast year. It reflects the present value of the stream of avoided electricity costs or accrued energy value of or associated with the distributed generation technology. Depending on the technology, this value may reflect variable retail electricity (energy) costs, parallel generation tariffs, wholesale energy costs, or a blend based on technology assumptions. The LVOE metric is similar to the EIA's National Energy Modeling System's use of levelized avoided cost of electricity (LACE)[7], though this report uses the LVOE term to avoid semantic confusion with the PURPA definition of avoided cost from a utility's perspective.[8]

For the WPL distributed generation forecast, we developed levelized values of energy for two rate classes (GS and CP-1), parallel generation tariffs, and wholesale electricity prices.[9] In all cases, the LVOE is based on the energy provided. Natural gas costs and avoided demand charges are incorporated into the LCOE. In each case, a 15-year and 20-year forecast was developed to reflect the nominal levelized net present value of electricity (energy) using the utility weighted average cost of capital as a proxy for a general discount rate. Inflation factors were based on general inflation rates estimated by Wood Mackenzie. Although current tariffs were used to form the basis of the LVOE (excluding the wholesale LVOE), the LVOEs used in the forecast should not be viewed as forecasts of future rates—rates were used as the starting point to reflect customer value propositions.

The blending of the resulting LVOEs reflects assumptions regarding each technology's percentage of customer load offset (at retail) or energy exports (at parallel generation or wholesale value). Table 3-2 describes each technology's assumptions regarding the blending of the LVOEs for each scenario. Technology specific LVOEs for each year are presented in the subsequent technology sections.

[7] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
[8] PURPA refers to the Public Utilities Regulatory Policies Act. The definition of avoided cost has changed over time and has state by state variances, but often is referred to as the utility's incremental cost of avoided energy or capacity.
[9] Wholesale electricity price forecasts were provided by WPL and from a Wood Mackenzie forecast.

Table 3-2. LVOE Blending by Technology

Technology and Project Life	Scenario		
	Base Case	Low-policy	High-policy
Solar			
>20 kW <100 kW 20 years	50% GS 20% PG on-peak 30% PG off-peak	50% GS 20% wholesale on-peak 30% wholesale off-peak	50% GS 20% PG on-peak 30% PG off-peak
100 kW and over 20 years	70% CP-1 on-peak 30% CP-1 off-peak	70% CP-1 on-peak 30% CP-1 off-peak	70% CP-1 on-peak 30% CP-1 off-peak
Wind			
Medium wind 20 years	34% GS 33% PG on-peak 33% PG off-peak	34% GS 33% PG on-peak 33% PG off-peak	34% GS 33% PG on-peak 33% PG off-peak
MW-Class wind 20 years	36.7% PG on-peak 63.3% PG off-peak	36.7% wholesale on-peak 63.3% wholesale off-peak	36.7% PG on-peak 63.3% PG off-peak
Biogas			
Wastewater treatment plant 20 years	CP-1 12 hr on-peak/off-peak summer/winter blend	CP-1 12 hr on-peak/off-peak summer/winter blend	CP-1 12 hr on-peak/off-peak summer/winter blend
Dairy farm digester 15 years	PG on-peak/off-peak blend	Wholesale on-peak/off-peak blend	PG on-peak/off-peak blend
Combined Heat and Power			
All CHP technologies 15 years or 20 years	CP-1 12 hr on-peak/off-peak summer winter blend; 66% on-peak 34% off-peak	CP-1 12 hr on-peak/off-peak summer winter blend; 66% on-peak 34% off-peak	CP-1 12 hr on-peak/off-peak summer winter blend; 66% on-peak 34% off-peak

C. Applying LCOE and LVOE

After developing each technology's LCOE and LVOE for an investment that could occur in each year of the forecast, the two values were compared to determine investment options. When the LVOE exceeded the LCOE, adoptions of the technology were assumed to be possible. From a customer's perspective and depending on the technology, the implication is that a given distributed generation technology may be preferred over purchasing retail electricity or selling electricity at parallel generation tariffs or wholesale prices. We note that any given customer's specific investment criteria, risk perceptions, competitions for capital, cost of capital, and tastes or preferences will drive decisions on whether to invest in distributed generation technology or not. The comparison of LCOE and LVOE should not be viewed as a specific financial pro forma analysis, but rather a general disposition of distributed generation investment perspectives in the broad market.

4. SOLAR ELECTRIC

4.1 TECHNOLOGY OVERVIEW

Distributed solar electric systems (photovoltaics) have seen a steep rise in adoption in the WPL service territory since 2007, when WPL had approximately 137 kW of distributed solar electric capacity. At the end of 2013, that capacity grew to 4,793 kW. During the 2008–2013 timeframe, federal- and state-level incentives and utility solar tariffs were active in the WPL market. Additionally, the solar electric market exhibited significant price decreases for installed system costs.[10]

The vast majority of WPL solar electric systems are systems 20 kW and less. While some of these systems are operating under an advanced renewable tariff (ART), they are of a net metered size. In addition, while approximately 52 percent of solar capacity is above the net metering threshold, the majority of this capacity comes from a single customer with 2,200 kW of solar. Very few customers have installed systems above net metering limits. Table 4-1 illustrates the capacity size breakdown of distributed solar electric systems installed in WPL's service territory through 2013.

Table 4-1. WPL Distributed Solar Segmentation, EOY 2013

Segment	System Count	Total DC Solar Electric Capacity	Average DC kW	Percent of Solar Electric Capacity
20 kW and less	341	2,233 kW	6.5 kW	46.6%
20 kW to 100 kW	5	260 kW	52 kW	5.4%
100 kW and over	2	2,300 kW	1,150 kW	48.0%
Total	348	4,793 kW		100.0%

As illustrated in Table 4-1, larger systems (>20 kW) have relatively few installations, though the total capacity is significant. All of these larger systems were installed between 2010 and 2012, signifying large growth in this segment. However, with zero additions in 2013, this segment appears to have sensitivity to market conditions.

While the growth experienced up to 2013 is significant, it is less clear that future growth will continue at the same level. For systems 20 kW and less, growth has significantly slowed. The steep rise from 2008 through 2010 averaged 139 percent annual growth in cumulative capacity, with cumulative growth in 2011 and 2012 averaging 25 percent. The growth from 2012 to 2013 was only 6 percent. The changes in the growth rates are likely due to several factors, including:

- The Focus on Energy program substantially reducing incentive levels and budget for solar installations
- The full subscription and closing of the ART
- Possible shifts in technology diffusion moving beyond early adopters.

[10] "Tracking the Sun VI – An Historical Summary of the Installed Price of Photovoltaics in the united States from 1998 to 2012." Barbose et al. July 2013. Lawrence Berkeley National Laboratory.

For the larger systems (over 20 kW), WPL has a very limited history. Focus on Energy funding may have assisted with systems less than 100 kW, but for the systems over 100 kW, decisions by specific customers drove the expansion of solar capacity. The WPL territory does not appear to exhibit a steady adoption of systems over 20 kW, though clearly the effect of individual customers can have a large effect on the total installed capacity.

That WPL has significantly greater technical potential for solar electric systems is without a doubt and not part of our forecast considerations. Given the assumed high technical potential, our solar forecast focuses on estimating market behavior in response to economic signals. We assume that the WPL electric system and solar market has significant room for growth without creating technical challenges or reaching market saturation during the forecast period. In the next section we describe our methodology to estimate the addition of solar electric capacity in the WPL territory through 2029.

4.2 METHODOLOGY

The methodology we used to forecast additional distributed solar electric systems relies on several key assumptions:

- General market adoptions will continue through 2016, reflecting the 2012–2013 market growth rate for systems less than 20 kW.
- Energy Information Administration (EIA) AEO 2013 projections for cumulative growth rates of non-marketed solar electric systems are applicable to the WPL solar electric market in 2017 and later.
- Growth patterns through 2016 will reflect the presence of the federal ITC at 30 percent, with a drop to 10 percent for the base case and low-policy support case.
- Existing capacity is maintained or replaced at the same level of performance, with the forecast reflecting incremental additions of solar electric capacity.
- Energy production estimates can be modeled using PVWatts v.1[11] default fixed-tilt system inputs with Madison, Wisconsin as the representative location of systems.
- There are no system technical constraints to adding distributed solar capacity during the forecast period.
- Economics will drive customer decisions for systems greater than 20 kW.

To model energy production for solar electric systems, PVWatts v.1 provides estimates of AC system output using standard equations and derates for system components, shading, and other factors. Using PVWatts v.1, we estimated that each 1 kW of DC solar system capacity could be expected to produce 1,231 kWh of electricity each year. While PVWatts v.1 shows a two-axis tracking system producing 1,617 kWh per kW of DC capacity per year, we selected the fixed axis system as the default due to a lack of information regarding WPL market adoptions of tracking systems.

[11] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/.

For a fixed-axis PV system, the

PVWatts default input values are as follows:

- 0.77 DC to AC derate (accounts for multiple derate factors within PVWatts)
- Fixed tilt axis
- 43.1 degree array tilt (line of latitude for Madison, WI)
- 180 degree array azimuth (pointing due south).

Table 4-2 illustrates technical and market assumptions that underlie the market forecast. Net-metering sized systems are represented by a 5 kW DC system, with larger nonresidential systems represented by 50 kW and 500 kW systems.

Table 4-2. Distributed Solar Electric System Characteristics

	Net metered	50 kW Nonresidential	500 kW Nonresidential
Capacity (DC kW)	5	50	500
Capacity (AC kW)	3.85	38.5	385
Estimated kWh, Madison, WI	6,157	[redacted]	[redacted]
Installed cost per kW (in 2012)[12]	$4,900	[redacted]	[redacted]
Fixed O&M (2012$ per kW-yr)[13]	$20	[redacted]	[redacted]
Variable O&M	$0	[redacted]	[redacted]

For systems 20 kW and less, the forecast does not rely directly on a the economics of the technology. In this market segment, we assumed that WPL customers are installing solar electric systems for multiple reasons, only some of which *may* be economic. Many estimates of solar electric economics indicate that despite the presence of incentives, many adoptions would not be economically beneficial from a traditional financial performance perspective. Further, this market segment has seen major variability over the last six years, making any pattern related to the underlying economics difficult to discern. We assume the 6 percent cumulative growth rate experienced in 2013 will continue through 2016. After 2016, the EIA's reference case forecast for national growth in customer-sited systems is used for the base case and reduced by 75 percent for the low-policy case. For the high-policy case the EIA's no sunset case is used to model the cumulative growth rates after 2016. Table 4-3 summarizes these assumptions.

[12] Barbose, Galen, Naïm Darghouth, Samantha Weaver, and Ryan Wiser. "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012." Lawrence Berkeley National Laboratory, 2013. P. 23.

[13] Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke. "Cost and Performance Assumptions for Modeling Electricity Generation Technologies." National Renewable Energy Laboratory 2010.

Table 4-3. Forecasted Growth Rates for Solar <20 kW, Key Time Periods

Time Period	Annual Cumulative Growth Rate	Assumptions
2014–2016 (all scenarios)	6.0 percent	Based on 2013 cumulative growth from 2012; reflects current ITC and market
Base Case 2017–2029	2.0 percent (average)	EIA reference case cumulative growth rates
High-Policy Case 2017–2029	7.8 percent (average)	EIA no sunset case cumulative growth rates
Low-Policy Case 2017–2029	0.4 percent (average)	25 percent of EIA reference case cumulative growth rate

For systems over 20 kW, the forecast model assumes that customers are installing systems as an economic decision. The installation of systems between 20 kW and 100 kW in 2010 and 2011, with no further installations through 2013, suggests that customers are responding to an economic signal. We also note that the federal ITC was the only active incentive in operation from 2010 through 2013, indicating that incentives over and above the ITC were needed to tip the decision toward installing a solar system and potentially explaining the lack of installations of systems in the 20 kW to 100 kW size range.

The economic model relies on a long-term assumption that solar electric prices will decline in nominal terms at 7 percent per year during the forecast period.[14] With increasing electricity prices and assumptions regarding the value of energy being offset, the economic model estimates that cost effectiveness will be achieved for 50 kW systems and 500 kW systems during the forecast period. Table 4-4 illustrates the findings for each of these systems in each scenario.[15]

Table 4-4. Calendar Year of Model Cost-Effectiveness

System Size	50 kW	500 kW
Year Cost Effective		
Base Case	2022	2025
Low-Policy case	2023	2025
High-Policy case	2018	2021

Several assumptions regarding energy values are used to determine cost effectiveness. The model uses a levelized value of energy in which to compare the levelized cost of energy for a solar electric system. For the 500 kW system, we assume that 100 percent of the energy will

[14] Barbose, Galen, Naïm Darghouth, Samantha Weaver, and Ryan Wiser. "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012." Lawrence Berkeley National Laboratory, 2013. P. 14.

[15] A 50 kW system was used to represent the economics of >20 kW and <100 kW solar electric systems. Similarly, a 500 kW system was used to represent the economics of solar electric systems over 100 kW. These representations are meant to capture the range of possible economics of such systems and not reflect specific 50 kW or 500 kW systems.

be used internally to the customer and offset the variable energy portion of industrial rates, following the on-peak and off-peak schedule of those rates. In the case of the 50 kW system, we assume that customers will be on a general service rate, with half the production offsetting retail consumption and the balance being exported on an instantaneous basis at the parallel generation rate (base case and high-policy case) or wholesale energy value (low-policy case).

Table 4-5 and Table 4-6, respectively, present the underlying LCOE and LVOE estimates of the 50 kW and 500 kW prototypical systems used to determine cost effectiveness.

Table 4-5. 50 kW Nonresidential Solar LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

Table 4-6. 500 kW Nonresidential Solar LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

For years in which systems are estimated to be cost effective, the model assumes that customers will install systems. For the 50 kW systems, we assume that the capital available to do so will be present based on the historical installations rate for WPL. In the case of the 500 kW systems, the model relies on Wisconsin statewide installation data, prorating the potential capacity by WPL's share of retail electricity sales in 2010 (14.8 percent).[16] Table 4-7 illustrates the underlying assumptions in the capital availability portion of the forecast model.

[16] http://www.eia.gov/electricity/state/wisconsin/pdf/wisconsin.pdf.

Table 4-7. Capital Availability Assumptions

System Size	50 kW	500 kW
Total installed capacity	[redacted]	[redacted]
Number of years current capacity installations have occurred	2	7
Avg kW per year (base year)	[redacted]	[redacted]
Capital availability factors		
Economic growth	[redacted] percent per year	
Inflation	[redacted] percent per year	
Factor in 2029[17]	[redacted]	[redacted]

The model makes a final adjustment to the largest category of solar systems for the high-policy case. Our solar and MW-class wind economic models revealed that in the last three years of the forecast period (2027–2029), large solar systems have a lower levelized cost of energy than MW-class wind systems. As such, it is possible that investment choices may shift to favor large solar systems. To account for this potential, we assumed that 50 percent of the capital available for MW-class wind systems would be applied to large solar systems. The result is a significant increase in large solar systems in the last three years of the forecast period. We note that our forecast estimate may be underestimating this shift from MW-class wind to large PV systems—depending on specific conditions in the market, that shift could occur sooner and at a greater percentage than in our model. If the market does make this shift, substantially higher kW of large solar will be installed at the expense of potential MW-class wind installations. However, the net effect on total MWh from distributed generation will be muted due to the lower capacity factor of solar electric systems. For the base case and low-policy case, the economics of MW-class wind result in little or no installation and is not considered in either of those cases. The issue is only considered for the high-policy case and is a point of uncertainty within the overall forecast regarding specific technology adoptions.

4.3 RESULTS

The WPL total figures contain all the rating and projected annual output of WPL's service territory. The findings are reported as additional kW and additional kWh, discounting Alliant Energy's current capacity through 2013. Peak summer MW contribution is based on a multiplier of 47.3 percent of AC capacity, based on Black and Veatch modeling of Alliant Energy's hourly load profile.

[17] The factor in 2029 represents the availability of nominal dollars that could be applied to solar electric systems compared to the base year. For example, a factor of 2.0 means that twice the nominal dollars are available in that year than in the base year. With declining nominal capacity prices, each subsequent year after the base year will have more kW potential per dollar of available capital. By way of example, for a year with twice the capital available as the base year and with half the per kW capital cost, four times the potential kW is forecasted over the base year.

Table 4-8. Base Case Distributed Solar PV WPL Forecast, 2014–2029

Year	20 kW and less (MW DC)	>20 and < 100 kW (MW DC)	Over 100 kW (MW DC)	WPL Total MW DC	WPL Total MWh	WPL Total Summer Peak MW AC
2014	0.134	-	-	0.134	165	0.048
2015	0.276	-	-	0.276	340	0.099
2016	0.427	-	-	0.427	525	0.153
2017	0.443	-	-	0.443	545	0.159
2018	0.461	-	-	0.461	568	0.166
2019	0.486	-	-	0.486	599	0.175
2020	0.516	-	-	0.516	636	0.186
2021	0.551	-	-	0.551	679	0.198
2022	0.587	0.422	-	1.009	1,243	0.363
2023	0.629	0.894	-	1.523	1,875	0.547
2024	0.676	1.422	-	2.098	2,584	0.754
2025	0.726	2.014	0.580	3.320	4,089	1.194
2026	0.776	2.677	1.229	4.683	5,766	1.683
2027	0.832	3.420	1.956	6.208	7,645	2.232
2028	0.901	4.251	2.770	7.922	9,756	2.848
2029	0.969	5.182	3.681	9.832	12,109	3.535

Table 4-9. Low-Policy Case Distributed Solar PV WPL Forecast, 2014–2029

Year	20 kW and less (MW DC)	>20 and < 100 kW (MW DC)	Over 100 kW (MW DC)	WPL Total MW DC	WPL Total MWh	WPL Total Summer Peak MW AC
2014	0.134	-	-	0.134	165	0.048
2015	0.276	-	-	0.276	340	0.099
2016	0.427	-	-	0.427	525	0.153
2017	0.431	-	-	0.431	530	0.155
2018	0.435	-	-	0.435	536	0.156
2019	0.441	-	-	0.441	544	0.159
2020	0.449	-	-	0.449	553	0.161
2021	0.457	-	-	0.457	563	0.164
2022	0.466	-	-	0.466	574	0.168
2023	0.476	0.472	-	0.948	1,168	0.341
2024	0.487	1.001	-	1.488	1,832	0.535
2025	0.499	1.593	0.580	2.671	3,290	0.960
2026	0.510	2.256	1.229	3.995	4,920	1.436
2027	0.523	2.998	1.956	5.477	6,745	1.969
2028	0.539	3.829	2.770	7.138	8,790	2.566
2029	0.554	4.760	3.681	8.995	11,077	3.234

Table 4-10. High-Policy Case Distributed Solar PV WPL Forecast, 2014–2029

Year	20 kW and less (MW DC)	>20 and < 100 kW (MW DC)	Over 100 kW (MW DC)	WPL Total MW DC	WPL Total MWh	WPL Total Summer Peak MW AC
2014	0.134	-	-	0.134	165	0.048
2015	0.276	-	-	0.276	340	0.099
2016	0.427	-	-	0.427	525	0.153
2017	0.844	-	-	0.844	1,039	0.303
2018	1.269	0.268	-	1.537	1,893	0.552
2019	1.701	0.568	-	2.269	2,795	0.816
2020	2.230	0.905	-	3.135	3,860	1.127
2021	2.761	1.281	0.369	4.411	5,432	1.586
2022	3.291	1.703	0.782	5.776	7,113	2.076
2023	3.836	2.175	1.244	7.255	8,935	2.608
2024	4.388	2.704	1.762	8.853	10,903	3.183
2025	4.955	3.296	2.341	10.592	13,044	3.808
2026	5.521	3.959	2.991	12.470	15,357	4.483
2027	6.083	4.701	5.065	15.849	19,518	5.698
2028	6.645	5.532	7.388	19.566	24,095	7.033
2029	7.206	6.463	9.990	23.659	29,135	8.505

5. WIND ENERGY

5.1 TECHNOLOGY OVERVIEW

Table 5-1. Distributed Wind Systems in WPL through 2013

Wind Market Category	2013 EOY Installed Capacity	Percent of Distributed Wind Capacity	Total Capacity Growth 2007–2013
Small wind (less than 50 kW)	538 kW	61 percent	296 kW
Medium wind (50 kW to 750 kW)	345 kW	39 percent	150 kW
MW-class (750 kW to 10 MW)	0 kW	0 percent	0 kW
Total WPL DG wind	883 kW	100 percent	446 kW

During the 2008–2013 timeframe, a number of policy and market forces influenced the distributed wind market in the WPL service territory. These include the federal production tax credit (PTC), the federal investment tax credit (ITC), the Rural Energy for America Program (REAP), and Focus on Energy incentives. Investors and developers of MW-class distributed wind projects sought to capture these incentives and leverage the technology and knowledge base of the utility-scale wind market. For small and medium wind, the market has shown maturation, with greater customer awareness and interest coupled to greater product availability. Along with favorable incentives, these factors may have been the significant market forces driving the small and medium wind market.

Both MW-class and customer-sited wind face economic and policy challenges and opportunities for the 2014–2029 forecast period. For MW-class wind, the federal PTC and ITC conversion expired at the end of 2013. For customer-sited wind turbines, the federal ITC expires at the end of 2016. REAP is an uncertain source of federal incentives linked to the Farm Bill. The market for small and medium turbines can be expected to continue to reflect a maturing market with recently implemented equipment certification standards (AWEA 9.1) serving as a key driver of product quality.

With the existing pattern of distributed wind growth and the policy and market considerations in mind, we describe our forecasting methodology in the next section.

5.2 METHODOLOGY

5.2.1 Customer-sited wind systems

We assume that systems less than 750 kW are used by customers to offset their electricity loads and generally cover the “small and medium” size range of wind turbines. The methodology used to forecast small and medium wind systems relies on several key assumptions:

1) For WPL, systems 20 kW and less will be net metered, while systems larger than 20 kW (up to 750 kW) will receive only partial retail offset.

2) There is a large technical potential with market growth during the forecast period not limited by the electrical distribution system capacity or wind resource availability.

3) Growth patterns through 2016 will reflect the presence of the federal ITC in all scenarios.

4) Existing capacity is maintained or replaced at the same level of performance, with the forecast reflecting incremental additions of small and medium wind capacity.

5) Demand for small wind turbines will reflect national trends that are reflected in the Energy Information Administration 2013 Annual Energy Outlook.

6) Energy production estimates can be modeled using single turbines as examples of small and medium wind systems.

To model energy production from customer-sited wind systems, we used two models of existing turbines to represent prototypical wind turbines. A Bergey Excel 10 turbine (10 kW) was used to model small turbines, while a Northern Power 100 (100 kW) was used to model medium size turbines. Although a wide range of possible turbine capacities and performances can be expected for each of these size categories, these turbines serve to represent the kWh per kW performance, provide a reasonable production estimate and are frequently found in Wisconsin's distributed wind market.

A. Performance modeling for customer-sited wind

Small and medium wind turbines are developed based on system owner's geographic limits, and are not optimized by the ideal location setting of utility-scale wind farms. Put another way, owners are not able to select their wind resource, but must take advantage of the wind resource available to them. We reviewed the Wisconsin wind map from the National Renewable Energy Laboratory (NREL)[18] and selected a general [redacted] average wind speed resource from the maps to broadly represent an average small and medium wind resource from which the turbine-specific production estimates could be developed.

For both turbine models, we assumed an average wind speed of [redacted] to capture average performance. For any given installation, the wind resource will be different. The selection of the [redacted] wind speed was based on middle-quality wind resources found in the WPL territory, particularly southern Wisconsin. The production estimates for each system were based on integrating the manufacturer's power curve across a wind frequency distribution using MS-Excel's® Weibull equation and derating the output. This production method is standard for small and medium wind turbine site assessments and described in many industry publications.[19] Table 5-2 describes the key wind resource and production modeling assumptions and results for each turbine.

[18] http://www.nrel.gov/gis/wind.html.

[19] A general description of the approach can be found in: Gipe, Paul. *Wind Power: Renewable Energy for Home, Farm, and Business.* 2004, pp. 61-62. An application of this approach and the results can be found in Kasunic, C., Evans, J. & Hasselman, R. (June 18, 2013) Adventures in Wind Resource Assessment. Small Wind Conference, presentation conducted from Stevens Point, Wisconsin.

Table 5-2. Wind Resource and Production Modeling for Small and Medium Wind Turbines

Modeling Factor	10 kW Turbine (Small)	100 kW Turbine (Medium)
Manufacturer	Bergey	Northern Power
Model	Excel 10	[redacted]
80 m/s wind speed	6.5	
Turbine hub height	37 meters (120 feet)	
Wind shear alpha	0.30	
Weibull k factor	2.3	
Ground elevation above sea level	450 meters	
Power curve source	SWCC[20] certification	
Turbine derate[21]	20 percent	
Annual average kWh	10,417 kWh	
kWh/kW	1,042 kWh/kW	
Overnight capital cost[22]	$65,000	
O&M ($/kW-yr)[23]	$10.00	

B. *Forecasting small wind systems*

Our forecasting method for small wind turbines does not rely directly on the economics of wind technology. Rather, the forecasting method for small wind turbines considers the WPL market behavior from 2012 and 2013 to model 2014 through 2016, and then relies on the Energy Information Administration's (EIA) 2013 national forecast for *solar photovoltaic* growth for 2017–2029 for non-marketed solar energy. The 2012 and 2013 years were estimated to be a reasonable proxy to represent 2014–2016 for the small wind turbine market as they reflect market behavior occurring after Focus on Energy removed incentives for this market, but for which the federal ITC was still active.

The EIA's non-marketed wind forecast showed zero growth for non-marketed wind following the end of the federal ITC. Given the WPL market's growth in small wind systems prior to federal ITC availability, an assumption of zero growth in the years following the ITC appears unreasonable. In using the non-marketed annual cumulative growth rate of non-marketed solar photovoltaics from the EIA, the WPL forecast assumes a growth rate equal to half that of solar photovoltaics. The economics of customer-sited wind are relatively poorer in recent years than for solar electric systems and incur greater siting challenges and a more complex development path. Though some customers may prefer wind, solar electric systems are likely to provide significant ongoing competition. For the high-policy case, the EIA's non-marketed solar photovoltaic growth is also used as a proxy for customer-sited wind, just as in the base

[20] Small Wind Certification Council independent test results. http://www.smallwindcertification.org/.
[21] A turbine derate is used to capture losses from turbulence, yawing, electrical conversion efficiency, blade soiling and wear, and maintenance downtime.
[22] Personal communications with Bergey and Endurance Windpower, December 2013.
[23] http://www.windpoweringamerica.gov/pdfs/2012_annual_distributed_wind_market_report.pdf.

forecast (at half the cumulative growth rate). In the case of the low-policy support scenario, the base case forecasted annual growth is reduced by 75 percent starting in 2017, reflecting an impact of reduced interconnections in line with that experienced by Wisconsin Public Service from 2010 to 2013 and discussed in the report section describing the policy scenarios.

Table 5-3. Forecasted Growth Rates for Small Wind Capacity, Key Time Periods

Time Period	Average Annual Cumulative Growth Rate	Assumptions
2014 through 2016 (all scenarios)	4 percent	Based on average cumulative growth for 2012 and 2013
Base Case 2017–2029	0.9 percent	Half the cumulative EIA solar photovoltaic growth rate
High-Policy Case 2017–2029	3.9 percent	Half the cumulative EIA solar photovoltaic growth rate
Low-Policy Case	0.2 percent	25 percent of base case cumulative growth

C. Medium size wind economic modeling

For medium size customer-sited wind turbines, the forecast relies on an economic model to forecast potential installations. The economic model assumes that customers investing significant funds into medium size wind turbines are doing so for financial return. It is possible that in some cases, non-financial factors may extend or otherwise mitigate financial criteria. That said, the relatively few turbines installed in this size category since 2008 were installed during a time with high incentive availability, suggesting a financial motive drove the decision.

The economic model considers the levelized cost of energy (LCOE) from medium size turbines compared to the assumed levelized value using a 20-year forecast of retail, parallel generation tariffs and wholesale electricity prices. For each year of the forecast period a LCOE for medium size wind systems and a levelized value of energy were developed, allowing for a judgment of whether medium size wind systems would be attractive to develop in that year. In years where the levelized value exceeds the levelized cost, we assume investments would occur. Table 5-4 presents the medium size wind financial assumptions used in the base case and low-policy case. Given the variable nature of wind energy electricity production, we assume that system owners will only consume a portion of the wind system's electricity on an instantaneous basis. As a result, only a portion of the wind production is valued at retail, with the balance being valued at either parallel generation or wholesale values, depending on the scenario (described below).

Table 5-4. Medium Size DG Wind LCOE Assumptions, Base and Low-Policy Cases

LCOE Factor	LCOE Metric	Notes
Overnight capital cost ($/kW)	[redacted] per kW[24]	Held constant in nominal terms during the forecast period
O&M Cost ($/kW-yr)	[redacted][25]	Inflates by general rate of inflation
Marginal tax rate	35 percent	Assumes a tax paying entity with tax liability
MACRS NPV factor	0.288	NPV factor of 5-year MACRS depreciation tax effect
Salvage value	[redacted]	Assumes 20-year life with salvage value covering decommissioning costs
Discount rate	7.77 percent	Utility WACC provided by WPL
Inflation rate	[redacted] percent	General rate of inflation 2014–2029
System kW	[redacted] kW	Used to model energy production, O&M expenses and capital cost
Annual system kWh	[redacted] kWh	Annual energy production from representative system (100 kW)

For the three scenarios, we assume that medium size wind turbines will receive the federal ITC through 2016, reflecting a 30 percent reduction in capital costs. In the high-policy scenario, we assume that the 30 percent reduction in capital costs is continued through the forecast period.

To create a value of energy, we assume a blend of retail and parallel generation or wholesale prices. Given the variable nature of wind energy output and with less likelihood of significant generation during a business's operating hours, we assume the following blend to energy prices:

- 34 percent at retail offset at general service rates
- 33 percent export at parallel generation or wholesale price on-peak values
- 33 percent export at parallel generation or wholesale price off-peak values.

The base case and high-policy cases assume the energy value is based on retail offset and parallel generation rates, while the low-policy case assumes the energy value is based on a blend of retail offset and wholesale energy prices. Table 5-5 presents the estimated LCOE and LVOE for medium scale wind.

[24] Based on estimates provided by Northern Power Systems.
[25] http://www1.eere.energy.gov/wind/pdfs/2012_distributed_wind_technologies_market_report.pdf.

Table 5-5. Medium Wind LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

In comparing the levelized cost of medium scale wind energy to the levelized value of energy of medium scale wind, no scenario shows medium scale wind being cost effective in any year. As a result, the forecast assumes zero adoptions of medium scale wind.

5.2.2 MW-class wind systems

Distributed generation using MW-class wind systems was modeled using two core assumptions:

1) The energy performance can be modeled using a [redacted] turbine to represent the general class and range of MW-class wind systems.

2) The logic for the market to make such investments is based on a profit motive reflected in the cost of the energy relative to its market value.

A. Performance modeling

A representative wind resource of [redacted] was selected based on the NREL Wisconsin Wind Map, indicated as a better-than-average wind resource found in the WPL service territory.[26] Using the [redacted] power curve and assuming an [redacted] tower height, the [redacted] power curve was integrated across a [redacted] wind frequency distribution using MS-Excel and standard industry assumptions to derate the energy production. The resulting average annual energy production from the turbine is [redacted] percent capacity factor.

Wind turbine will have output that varies over time (daily and seasonally) and utility parallel generation rates are based on on-peak and off-peak times. We developed an estimate of the kWh that could be expected to occur during the parallel generation on-peak and off-peak periods. [redacted], we found that energy production could be expected to occur 36.7 percent during on-peak hours for the parallel generation tariff, with the balance occurring off-peak (63.3 percent). The location of [redacted] in a wind resource area broadly similar to the better wind resources found in WPL's service territory.

B. Economic modeling

The economic modeling assumed that financial returns drive investment decisions for distributed wind technology using MW-class turbines. Thus, past systems are assumed to have been installed in a situation that exhibited favorable economics. To forecast future additions of MW-class distributed wind technology we developed an economic model to understand when, if, and in what policy context distributed wind may become cost effective in the forecast period.

The economic model considers the levelized cost of energy from MW-class turbines compared to the assumed levelized value using a 20-year forecast of parallel generation tariffs and wholesale electricity prices. For each year of the forecast period a LCOE for MW-class wind and a levelized value of energy were developed, allowing for a judgment of whether MW-class wind would be attractive to develop in that year. In years where the levelized value exceeds the levelized cost, we assume investments would occur. Table 5-7 presents the MW-class wind financial assumptions used in the base case and low-policy case.

[26] http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=wi.
[27] [redacted]

Table 5-7. MW-class DG Wind LCOE Assumptions, Base and Low-Policy Cases

LCOE Factor	LCOE Metric	Notes
Overnight capital cost ($/kW)	[redacted]	Held constant in nominal terms during the forecast period[29]
O&M cost ($/kW-yr)	[redacted]	Inflates by general rate of inflation
Marginal tax rate	35 percent	Assumes a tax paying entity with tax liability
MACRS NPV factor	0.288	NPV factor of 5-year MACRS depreciation tax effect
Salvage value	[redacted]	Assumes 20-year life with salvage value covering decommissioning costs
Discount rate	7.77 percent	Utility WACC provided by WPL
Inflation rate	[redacted] percent	General rate of inflation 2014–2029
System kW	[redacted]	Used to model energy production, O&M expenses and capital cost
Annual system kWh	[redacted]	Annual energy production from representative system (3,000 kW)

For the low-policy case, we assume that wholesale electricity prices will be used to value wind energy. For the high-policy case, we assume that some mix of policies, market forces, and/or technology improvements results in a capital cost decrease of 25 percent, while utilizing the parallel generation tariff value of energy. All other factors in the economic model are held constant among all three scenarios.

The LVOE for MW-class wind is based on parallel generation tariffs for the base case and high policy case. For the low-policy case, wholesale electricity price forecasts are used to estimate the LVOE. The resulting LCOE and LVOE estimates for each year in the forecast period are shown in Table 5-8.

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[28] Based on a review of community wind case studies from Bolinger, Mark (2011). “Community Wind: Once Again Pushing the Envelope of Project Finance.” Lawrence Berkeley National Labs, January 2011.

[29] Prices for MW-class wind capacity have varied over the years, with small developments showing wide ranges. According to NREL data, costs have declined since a peak in 2010 and can be expected to further decline. We also speculate that community wind developments may become more cost effective as demand for utility-scale investments begins to taper and more turbine capacity is available, with the market also finding efficiencies in this size range of development.

[30] Tegen, S (et al 2010). “2010 Cost of Wind Energy Review” National Renewable Energy Laboratory, April 2012. Rounded to [redacted] to account for inflation.

Table 5-8. MW-class DG Wind LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

In comparing the values of energy to the LCOE estimates, only the high-policy case shows substantial opportunity for distributed MW-class wind. The high-policy scenario shows MW-class wind being cost effective beginning in 2017. The base case shows MW-class wind being cost effective only in the last two years of the forecast, 2028 and 2029. The low-policy case shows MW-class wind being not cost effective for any year of the forecast.

C. Forecast modeling

The WPL forecast for MW-class distributed wind energy is based on a review of the existing capacity and growth of similar wind developments in Wisconsin from 2011–2013. WPL hosts zero such systems, though only three have been developed state-wide, for a total of 18 MW[31]. Prior to that time period, such systems had not been developed anywhere in Wisconsin. Thus, the state shows an ability to raise capital and develop such projects at a rate of 6 MW per year. Assuming WPL's retail load reflects an economic ability to raise capital, WPL's 14.8 percent of Wisconsin's retail electricity sales suggest that WPL's service territory could raise capital to support 889 kW of MW-class wind per year.

[31] http://www.renewwisconsin.org/windfarm/windwisconsin.htm.

As these developments are driven by economic considerations, based on economic growth, future years would reflect greater capital availability for developing such projects. To estimate the potential capacity that could be installed in any year, our forecast method develops nominal capital availability on a MW basis by inflating the 889 kW per year by the rate of forecasted real economic growth and inflation rate.[32] The result is an estimate for each year of the WPL service territory's potential installation of MW-class distributed wind systems.

Using the potential capacity to install MW-class distributed wind, those years for which projects would be cost effective are identified for each scenario and assigned the potential capacity value for that year. This method assumes there are no technical limitations to interconnecting the systems in any year or by capacity. Table 5-9 describes the annual potential capacity of MW-class wind additions for a given year and the year's determination for cost effectiveness in each scenario.

The high-policy case exhibits significant potential for MW-class wind projects. However, it also exhibits significant potential for large solar projects (over 100 kW). The economic modeling shows that large solar levelized costs will drop below that of MW-class distributed wind during the last three years of the forecast. To account for likely substitution effects, we assume that half the potential MW-class wind investments would shift to large solar projects. The result is fewer *potential* MW-class wind projects in the high-policy scenario. Due to the marginal economics exhibited in the base case, with only two years late in the forecast for possible MW-class distributed wind capacity additions, no adjustments were made to that forecast in order to allow for some investments to occur and be modeled. Only in the more aggressive high-policy case, with robust competitive distributed generation markets operating, did we feel it appropriate to account for such substitutions.

[32] Based on Wood Mackenzie data and assumes [redacted] percent inflation and [redacted] percent real economic growth.

Table 5-9. MW-class Wind Potential Capacity and Scenario Cost Effectiveness

Year	Potential kW Base and Low- Policy Cases	Potential kW High-Policy Case	Pass Base Case Scenario	Pass High-Policy Scenario
2014	[redacted]		No	No
2015			No	No
2016			No	No
2017			No	Yes
2018			No	Yes
2019			No	Yes
2020			No	Yes
2021			No	Yes
2022			No	Yes
2023			No	Yes
2024			No	Yes
2025			No	Yes
2026			No	Yes
2027			No	Yes
2028			Yes	Yes
2029			Yes	Yes

5.3 RESULTS

The forecast modeling of customer-sited wind turbines (small and medium) along with MW-class wind turbines results in the incremental capacity additions shown in the following tables for each scenario. We assume that any existing capacity will be replaced as it deteriorates or is repowered. For modeling the summer peak kW contribution of wind energy, we assume 14.1 percent of generator capacity as the summer peak contribution. The 14.1 percent metric is based on the MISO average wind energy capacity credit per MISO effective load carrying capacity (ELCC) calculations.[33] The resulting summer peak contribution is calculated by multiplying the generator capacity by the 2014-2015 MISO system-wide wind capacity credit (14.1 percent).

[33] Midcontinent Independent System Operator (MISO). Planning Year 2014-2015 Wind Capacity Credit. December 2013. The ELCC is based on contributions to summer peak per MISO methods. For this study, the MISO capacity value is used to estimate the capacity value for all wind technologies.

Table 5-10. Base Case Cumulative Additional Distributed Wind WPL Forecast, 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-class MW	MW-class MWh	Total MW	Summer Peak MW	Total MWh
2014	0.020	21	-	-	-	-	0.0	0.0	21
2015	0.042	44	-	-	-	-	0.0	0.0	44
2016	0.066	68	-	-	-	-	0.1	0.0	68
2017	0.068	71	-	-	-	-	0.1	0.0	71
2018	0.071	74	-	-	-	-	0.1	0.0	74
2019	0.075	78	-	-	-	-	0.1	0.0	78
2020	0.080	83	-	-	-	-	0.1	0.0	83
2021	0.084	88	-	-	-	-	0.1	0.0	88
2022	0.089	93	-	-	-	-	0.1	0.0	93
2023	0.095	99	-	-	-	-	0.1	0.0	99
2024	0.102	106	-	-	-	-	0.1	0.0	106
2025	0.109	113	-	-	-	-	0.1	0.0	113
2026	0.115	120	-	-	-	-	0.1	0.0	120
2027	0.123	128	-	-	-	-	0.1	0.0	128
2028	0.131	137	-	-	1.8	4,276	2.0	0.3	4,413
2029	0.140	146	-	-	3.8	8,750	3.9	0.6	8,896

Table 5-11. Low-Policy Case, Cumulative Additional Distributed Wind WPL Forecast, 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-class MW	MW-class MWh	Total MW	Summer Peak MW	Total MWh
2014	0.020	21	-	-	-	-	0.0	0.0	21
2015	0.042	44	-	-	-	-	0.0	0.0	44
2016	0.066	68	-	-	-	-	0.1	0.0	68
2017	0.066	69	-	-	-	-	0.1	0.0	69
2018	0.067	70	-	-	-	-	0.1	0.0	70
2019	0.068	71	-	-	-	-	0.1	0.0	71
2020	0.069	72	-	-	-	-	0.1	0.0	72
2021	0.070	73	-	-	-	-	0.1	0.0	73
2022	0.072	75	-	-	-	-	0.1	0.0	75
2023	0.073	76	-	-	-	-	0.1	0.0	76
2024	0.074	78	-	-	-	-	0.1	0.0	78
2025	0.076	79	-	-	-	-	0.1	0.0	79
2026	0.078	81	-	-	-	-	0.1	0.0	81
2027	0.079	83	-	-	-	-	0.1	0.0	83
2028	0.081	85	-	-	-	-	0.1	0.0	85
2029	0.083	87	-	-	-	-	0.1	0.0	87

Table 5-12. High-Policy Case, Cumulative Additional Distributed Wind WPL Forecast, 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-class MW	MW-class MWh	Total MW	Summer Peak MW	Total MWh
2014	0.020	21	-	-	-	-	0.0	0.0	21
2015	0.042	44	-	-	-	-	0.0	0.0	44
2016	0.066	68	-	-	-	-	0.1	0.0	68
2017	0.097	101	-	-	1.1	2,593	1.2	0.2	2,694
2018	0.128	133	-	-	2.3	5,306	2.4	0.3	5,440
2019	0.158	164	-	-	3.5	8,146	3.7	0.5	8,310
2020	0.192	200	-	-	4.8	11,118	5.0	0.7	11,318
2021	0.225	234	-	-	6.1	14,228	6.3	0.9	14,463
2022	0.257	268	-	-	7.5	17,483	7.8	1.1	17,751
2023	0.288	300	-	-	9.0	20,889	9.3	1.3	21,189
2024	0.319	332	-	-	10.5	24,454	10.8	1.5	24,786
2025	0.349	363	-	-	12.1	28,184	12.5	1.8	28,548
2026	0.378	394	-	-	13.8	32,088	14.2	2.0	32,482
2027	0.406	423	-	-	14.7	34,131	15.1	2.1	34,554
2028	0.433	451	-	-	15.6	36,269	16.0	2.3	36,720
2029	0.459	478	-	-	16.6	38,506	17.0	2.4	38,985

6. BIOGAS

6.1 TECHNOLOGY OVERVIEW

Over the past decade biogas power generation technologies have advanced considerably. Wisconsin and WPL have seen growth in biogas power systems from landfills and anaerobic digesters located at wastewater treatment plants and dairy farms. Table 6-1 illustrates the current capacity of each of these biogas power generation technologies in the WPL service territory.

Table 6-1. Current Biogas Power Generation Capacity by Technology

Biogas Market Category	2013 EOY Installed Capacity	Number of Units	Percent of Biogas Generating Capacity	Capacity Installed 2004–2013	Number of Units 2004–2013
Landfill gas	9,235 kW	5	57 percent	5,475 kW	2
Dairy biogas	3,768 kW	4	23 percent	3,618 kW	3
Wastewater treatment biogas	3,233 kW	6	20 percent	3,233 kW	6
Total WPL DG biogas	16,236 kW	15	100 percent	12,326 kW	11

Three quarters of the biogas power systems and capacity were installed in the last decade. For developing the distributed market forecast we reviewed the adoption rates, conditions of past adoptions, and potential for future adoptions based on system economics and energy value.

In general, these types of systems are relatively small in scope with potential generation capacities ranging from the hundreds of kilowatts to approximately 2 megawatts, enabling interconnection at the distribution level. These systems typically use internal combustion engines to generate electricity, relying on a steady supply of biomass from which the biogas is created. Typically the generator must be placed in close proximity to the source of biogas. There is some potential for using a pipeline to deliver biogas at a distance, with a downside of adding cost and complexity to the development.

Projects involving landfills and wastewater treatment plants typically utilize facilities having a useful life of many decades, often more than 50 years. In contrast, farms may open, close, expand, or contract, leading to different planning horizons for the system owners. In general, biogas energy projects are developed based on investment criteria driven mostly by the value proposition of energy sales, but can be influenced by environmental regulations faced by the owner.

In general, the capital cost of a biogas-to-power system is substantial. In the case of landfills and wastewater treatment plants, much of the capital cost is part of the existing facility, with incremental costs related to biogas capture, cleanup, power generation, and grid interconnection. In contrast, for farm biogas, there are typically no existing biogas generation facilities, so the owner must invest in anaerobic digestion and support facilities, in addition to generation and interconnect requirements.

During the last decade, several policies and market forces influenced the biogas-to-energy market. These included the federal PTC, the federal ITC, the REAP program of the United States Department of Agriculture (USDA), and state level efforts to encourage market participation. In many cases, investors, owners and developers sought to capture the value of these incentives to decrease the burden of environmental compliance costs. Many of the systems installed in recent years took advantage of WPL's advanced renewable tariff (ART), which offered higher energy buy-back rates than the standard parallel generation tariff.

In our development of the base case, we found that all biogas-to-energy categories face stiff economic and policy challenges for the 2014–2029 forecast period. The federal PTC and ITC programs expired at the end of 2013, with no indication these tax programs will be renewed. The Focus on Energy program has focused its renewable energy efforts on biogas, which may provide a countervailing force against the expiration of the federal incentives.

For some select combined heat and power (CHP) systems and technologies, which includes biogas, a federal ITC remains in effect until the end of 2016. With the recent passage of the 2014 Farm Bill, REAP was renewed for an additional five years[34]. REAP grants and loan guarantees were funded with a blend of mandatory and discretionary programs that must still pass through federal budget authorization. REAP funds are awarded in a competitive process that has historically proven to be highly competitive. Our experience and review of past REAP awards suggests that the ratio of project applications to awards is approximately 10:1. As a result, REAP is not planned to be of significance to the point of driving forecast numbers, though it is possible that individual projects may ultimately receive REAP funds.

The farm and wastewater treatment plant biogas industry is relatively small and maturing. When combined with the significant additional capital requirements involved in installing projects, growth may be limited in this segment, though WPL does exhibit potential for additional growth in the forecast period, primarily on dairy farms. In contrast, we found that there is no landfill gas potential in the WPL territory during the forecast period. All landfills of sufficient capacity have been developed with gas projects, leaving only smaller landfills that the US EPA estimates as being too small for biogas development potential. We explain our methods and details of the analysis below.

6.2 METHODOLOGY

The methodology used to forecast biogas to power generation relies on several key assumptions:

1) These systems will be installed as an investment decision to supply power to the grid with owners paid for energy delivered based on a long-term power purchase agreement.
2) There is technical potential for market growth during the forecast period not limited by the electrical distribution system capacity or biomass resource availability.
3) Growth patterns through 2016 will reflect the presence of the federal ITC for select technologies.

[34] Agricultural Act of 2014.

4) Existing capacity is maintained or replaced at the same level of performance with the forecast reflecting incremental additions of biogas to energy capacity.

To model biogas to power generation we analyzed the biogas potential in three technology segments and sized generator capacity based on available internal combustion engine (ICE) generator sets (gen-sets) commonly used by the industry. For landfills and wastewater treatment plants, the biogas potential was estimated by considering specific facilities in the WPL service territory. For farm-based biogas, likely farm potential was developed using the USDA 2007 Census of Agriculture[35], the most recent version of the Census and statewide data regarding dairy biogas potential and adoption rates.[36] In all cases the systems are assumed to utilize biogas generation, collection, and cleanup technologies such that the biogas is useable in commercially available ICE gen-sets.

6.2.1 Landfill gas

In the landfill gas category we used the US EPA Landfill Methane Outreach Program (LMOP) database to determine the location, size, and longevity of landfills in the WPL service territory. Tetra Tech used three high-level criteria for screening landfills for biogas potential:

- The remaining useful life must be 15 years or greater
- The tonnage in place must be 850,000 tons or more[37]
- No current energy projects are operating at the landfill.

The LMOP database revealed that no landfills in Wisconsin met this criteria, excluding the WPL service territory from further consideration for landfill gas developments. While there is potential for landfills to expand or otherwise develop potential in the future, significant speculation is required to incorporate the smaller landfills into a distributed generation forecast. No further analysis was completed on landfill gas for the WPL service territory.

6.2.2 Wastewater treatment plants

In the wastewater treatment plant (WWTP) biogas category, we used the American Biogas Council (ABC) wastewater treatment plant inventory database to establish an initial list of facilities in each of Alliant Energy's service territories. This list was crosschecked by Alliant Energy staff to identify those facilities operating in the WPL service territory. Of the WWTP in WPL's service territory, we screened out those already producing electricity and those without an existing anaerobic digester. Based on industry standards for biogas potential per million gallons per day of sewage flow rate, we established the potential biogas generation rate for the remaining WWTP. The result was the identification of two WWTP with sufficient sewage

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[35] United States Department of Agriculture, 2007 Census of Agriculture, Summary and State Data, Washington, DC.

[36] Preliminary results of the 2012 Census of Agriculture were released in late February 2014. The data are incomplete and not yet suitable to use in this analysis; the full database is anticipated to be released in May 2014 according to the USDA 2012 Census of Agriculture website on Feb, 27, 2014.

[37] The LMOP Project Development Handbook (http://www.epa.gov/lmop/publications-tools/handbook.html) recommends that a landfill have 1,000,000 tons in place as a screening for potential. This study used 850,000 to allow for some growth and to identify potential landfills at the margins. The 15-year useful life is used to allow for one generator set lifecycle.

flow and existing anaerobic digesters that could generate power with engine gen-sets available in the market. The two WWTP would each be able to support a single 100 kW engine gen-set.

6.2.3 Dairy biogas

The WPL service territory hosts a substantial number of dairy farms with biogas development potential. We accessed the AgSTAR Project Database[38], finding that there are 29 farm anaerobic digester projects in Wisconsin. All are associated with dairy farms, other than one heifer raising facility. The AgSTAR Project Database indicated that the 29 projects created a total of 19 MW of connected biogas powered generating capacity.

WPL's data indicates that there are four interconnected dairy anaerobic digesters producing electricity on its system. Three of those four were developed from 2009–2013, indicating that when systems were cost effective, the service territory added three systems every five years, or 0.6 farm biogas projects per year. A total of 3,618 kW was installed through these projects, or approximately 1,206 kW per project or 724 kW per year.

Our forecast assumes that larger farms are more likely to install anaerobic digesters and associated electricity generating equipment. The Wisconsin Bioenergy Initiative indicates that there are 78 farms in Wisconsin with over 1,000 head of dairy cows, with 194 farms with between 500 and 999 head.[39] Assuming WPL's retail sales represent the proportion of these larger farms with biogas potential, WPL is potentially hosting 38 farms that could reasonably install biogas systems. That said, the three systems installed during 2009–2013 were between 600 kW and 2.1 MW each, indicating that larger farms are more likely to take action.

Our model assumes a possible range of engine gen-sets that could be installed—600 kW, 900 kW, and 1,200 kW. Assuming an equally likely split between the size ranges (33 percent each), at 0.6 biogas projects per year, the WPL service territory could expect to see an average of 520 kW per year developed on the system.

Our forecast further reduces the potential kW per year to account for the full subscription of the ART, as farms are unable to take further advantage of the higher buy-back rate for energy. We assume that rather than 0.6 biogas projects per year (or 1.67 years per project), one project would be developed every three years, even if cost-effectiveness was achieved. The recent dairy biogas systems were developed during a time when significant incentive funding and higher buy-back rates were available, reflecting a high-policy support environment. Without the availability of the ART, a significant incentive is not included for even the high-policy scenario, with the reduction in biogas development rates being nearly halved to the three years per project we assume. At this lower rate, assuming an equal blend of 600, 900, and 1,200 kW generating units being added, an average of 286 kW per year is forecasted as the market potential for WPL's service territory.

[38] Accessed on January 16, 2014.
[39] Wisconsin Bioenergy Initiative. The Biogas Opportunity in Wisconsin: 2011 Strategic Plan.

6.2.4 Economic modeling

In all biogas technology categories, we assumed that financial returns drive investment decisions. To forecast future additions of biogas generating capacity, we developed an economic model to understand when, if, and in which scenarios biogas generation may become cost effective during the forecast period. Although some categories of biogas systems, particularly farm based, may derive revenue from other components of the system (solid fertilizer or compost), our experience finds that these sources of revenue are not enduring, contractible, or investment grade and do not influence investment decisions. Therefore, no revenue beyond the sale of energy was factored into the cost model used for this analysis.

In all categories, the basic economic model considers the levelized cost of energy (LCOE) compared to the estimated levelized value of energy sales based on parallel generation tariffs. For each year of the forecast period an LCOE for each biogas technology and a levelized value of energy were developed, allowing estimation of whether biogas generation would be attractive to develop in a given year. In years where the value of energy exceeds the LCOE, we assume investments may occur. Table 6-2 through Table 6-3 describe the assumptions of the LCOE analysis.

Table 6-2. Biogas Wastewater Treatment Plant (WWTP) LCOE Assumptions

WWTP LCOE Factor	LCOE Metric	Notes
System kW	100	
Overnight capital cost ($/kW)	[redacted]	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008; 2G Cenergy Power Systems Technologies Inc., Biogas CHP Cogeneration Module Product Line Data Sheet, 04/01/2013
Annual system MWh	[redacted]	Assumes 90 percent capacity factor
O&M cost ($/kW-yr)	[redacted]	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008
Marginal tax rate	35%	assumed
MACRS NPV factor	0.288	NPV factor of the 5 year MACRS depreciation schedule
Salvage value	[redacted]	Useful life assumed to be 15 years
Discount rate	7.77	Utility weighted average cost of capital provided by WPL
Inflation rate	[redacted] percent	General rate of inflation 2014–2029; applied to capital and O&M costs

Table 6-3. Biogas Farm LCOE Assumptions

Farm LCOE Factor	LCOE Metric			Notes
System kW	600	900	1,200	
Overnight capital cost ($/kW)	[redacted]	[redacted]	[redacted]	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008; 2G Cenergy Power Systems Technologies Inc., Biogas CHP Cogeneration Module Product Line Data Sheet, 04/01/2013
Annual system MWh	[redacted]	[redacted]	[redacted]	Assumes 90 percent capacity factor
O&M cost ($/kW-yr)	[redacted]	[redacted]	[redacted]	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008
Marginal tax rate	35%			assumed
MACRS NPV factor	0.288			NPV factor of the 5-year MACRS depreciation schedule
Salvage value	[redacted]			Useful life assumed to be 15 years
Discount rate	7.77			Utility weighted average cost of capital provided by WPL
Inflation rate	[redacted] percent			General rate of inflation 2014–2029

For farm biogas, the resulting LCOEs are the same, regardless of generator capacity. For the high-policy scenario, we assume that WWTP biogas systems will receive the benefit of policy reducing capital costs by 25 percent. For dairy biogas systems, we assume a reduction of 40 percent of capital costs, reflecting a combination of federal, state, and utility policy effects to stimulate methane capture and utilization.

To estimate the LVOE against which the LCOE is compared, we developed estimated values using a mix of retail, parallel generation, and wholesale price forecasts. For WWTP systems, we assume the energy will offset retail energy purchases behind the meter. A blended value reflecting the variable portion of WPL's current 12-hour industrial customer tariff was used and inflated for the life of the system. The on-peak and off-peak components were blended to create a single value for energy. For dairy biogas systems, we assumed that the parallel generation tariff represented the value of energy for the base case and high-policy case, inflating the tariff by the rate of inflation. The on-peak and off-peak hours were used to create a weighted average value of energy. For the low-policy case, the Wood Mackenzie wholesale round-the-clock price forecast was used to create the LVOE for dairy biogas. Table 6-4 and Table 6-5 present the LCOE and LVOE for wastewater treatment plants and dairy biogas systems for each year of the forecast, respectively.

Table 6-4. WWTP Biogas LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					

Table 6-5. Dairy Biogas LCOE and LVOE ($/MWh)

Year	Base Case	Low Policy Case	High Policy Case
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			

In comparing WWTP energy costs to values, systems are cost effective in all scenarios. For both the base case and low-policy case, cost effectiveness begins in 2014 and continues through the forecast, though margins between cost and value are slight early in the forecast. In the high-policy case, assuming that policy were enacted in 2014, systems would also be cost effective in 2014 and through the entire forecast period. As a result, we assume that the total 200 kW of WWTP biogas will be developed during the forecast period. However, due to development lag-times (assumed to be five years), the high-policy case assumes one system will be developed in 2019 and the second in 2020. For the base case and low-policy case, we forecast these systems being developed with a two year lag behind the high-policy case, beginning in 2021 and finishing in 2022.

For farm biogas the economic model finds that no systems would be installed in either the base case or low-policy case. In the high-policy case, systems are theoretically attractive investment through the entire time period. However, we assume that policy delays, uncertainties, and development time will delay installations until 2019. Beginning in 2019, biogas systems are forecasted to occur for the remainder of the forecast period.

6.3 RESULTS

The forecast modeling of biogas generation results in the capacity additions shown in Table 6-6 through Table 6-7.

Table 6-6. Cumulative Additional Biogas Capacity and Production, Wastewater Treatment Plants and Farm-Based Anaerobic Digesters, 2014–2029, Base Case and Low-Policy Scenarios

Year	Cumulative WWTP MW	Cumulative Farm AD MW	Cumulative Summer Peak MW (WWTP and Farm)	Cumulative Annual MWh (WWTP and Farm)
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	-	-	-	-
2020	-	-	-	-
2021	0.100	-	0.090	788
2022	0.200	-	0.180	1,577
2023	0.200	-	0.180	1,577
2024	0.200	-	0.180	1,577
2025	0.000	-	0.180	1,577
2026	0.200	-	0.180	1,577
2027	0.200	-	0.180	1,577
2028	0.200	-	0.180	1,577
2029	0.200	-	0.180	1,577

Table 6-7. Cumulative Additional Biogas Capacity and Production, Wastewater Treatment Plants and Farm-Based Anaerobic Digesters, 2014–2029, High-Policy Scenario

Year	Cumulative WWTP MW	Cumulative Farm AD MW	Cumulative Summer Peak MW (WWTP and Farm)	Cumulative Annual MWh (WWTP and Farm)
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	0.100	0.286	0.347	3,043
2020	0.200	0.572	0.695	6,086
2021	0.200	0.858	0.952	8,341
2022	0.200	1.144	1.210	10,596
2023	0.200	1.430	1.467	12,851
2024	0.200	1.716	1.724	15,106
2025	0.200	2.002	1.982	17,361
2026	0.200	2.288	2.239	19,615
2027	0.200	2.574	2.497	21,870
2028	0.200	2.860	2.754	24,125
2029	0.200	3.146	3.011	26,380

7. COMBINED HEAT AND POWER

7.1 TECHNOLOGY OVERVIEW

Combined Heat and Power (CHP) is a form of distributed generation (DG) that involves the placement of electric power generating units at or near customer facilities to supply onsite heat and electricity. CHP provides benefits to owners by simultaneously producing useful thermal and power output, with total system efficiencies potentially leading to better economics than buying heat and power as individual energy sources. The advantages of CHP broadly include the following:

- CHP units can be strategically located at the point of energy use.
- Onsite generation avoids the transmission and distribution losses associated with energy purchased via the grid from central power stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

WPL currently has only a few customers that own CHP systems. Two of these systems are very large—over 10 MW. The remaining systems total 7.5 MW, with a range of 125 kW up to 6,000 kW. Fuel sources for CHP can vary. Biomass, biogas, fuel oil, and natural gas are all options. For purposes of forecasting distributed generation from CHP, we focus on natural gas systems as the most replicable and economic fuel option. Individual customers may choose different fuels—the focus on natural gas fueled systems is not to discount those possibilities, but to develop a generalizable understanding of a market that may grow in the future.

The forecast assumes that customers will invest in CHP systems based on economic returns. Our model is similar to other DG technologies presented in this report. We compare the levelized cost of energy to the value of that energy across a number of different CHP technology options and sizes.

The size ranges we considered for the forecast range from 200 kW to 5.3 MW. This size range has broad applicability in the market and avoids customer-specific modeling required for larger systems. Table 7-1 and Table 7-2 provide a summary of the key cost and performance characteristics of common CHP technologies.

Table 7-1. Summary of CHP Technologies[40]

CHP system	Advantages	Disadvantages	Available sizes
Gas turbine	High reliability. Low emissions. High-grade heat available. No cooling required.	Require high pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 250 MW
Microturbine	Small number of moving parts. Compact size and light weight. Low emissions. No cooling required.	High costs. Relatively low mechanical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW
Spark ignition (SI) reciprocating engine	High power efficiency with part-load operational flexibility. Fast start-up. Relatively low investment cost. Can be used in island mode and have good load following capability. Can be overhauled on site with normal operators. Operate on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions. Must be cooled even if recovered heat is not used. High levels of low frequency noise.	< 5 MW in DG applications
Compression ignition (CI) reciprocating engine (dual fuel pilot ignition)	High speed (1,200 RPM) ≤4MW Low speed (102–514 RPM) 4–75 MW		High speed (1,200 RPM) ≤4MW Low speed (102–514 RPM) 4–75 MW
Fuel cells	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low durability and power density. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW

[40] US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008.

Table 7-2. Summary Table of Typical Cost and Performance Characteristics by CHP Technology[41]

Technology	Internal Combustion Engine	Gas Turbine	Microturbine	Fuel Cell
Power efficiency (HHV)	[redacted]			
Overall efficiency (HHV)				
Effective electrical efficiency				
Typical capacity (MWe)				
Typical power to heat ratio				
Part-load				
CHP installed costs ($/kWe)				
O&M costs ($/kWhe)				
Availability				
Hours to overhauls				
Start-up time				
Fuel pressure (psig)				
Fuels	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
Noise	high	moderate	moderate	low
Uses for thermal output	[redacted]			
Power density (kW/m2)				
NO_x (lb/MMBtu) (not including SCR)				
lb/MWhTotalOutput (not including SCR)				

[41] Ibid.

For purposes of forecasting additional DG CHP installations in the WPL service territory, our analysis used a range of typical DG CHP systems and sizes currently in service in the US. These included:

1) Fuel cells at 300 kW and 1,400 kW
2) Combustion turbines at 2,900 kW and 5,280 kW
3) Internal combustion engines at 500 kW and 1,500 kW
4) Microturbines at 200 kW.

For policy interventions, there are no new state or local incentive programs to support CHP. At the federal level, an ITC remains in effect until the end of 2016, offering a tax credit of 30 percent of installed cost for fuel cells and 10 percent for other CHP technologies.

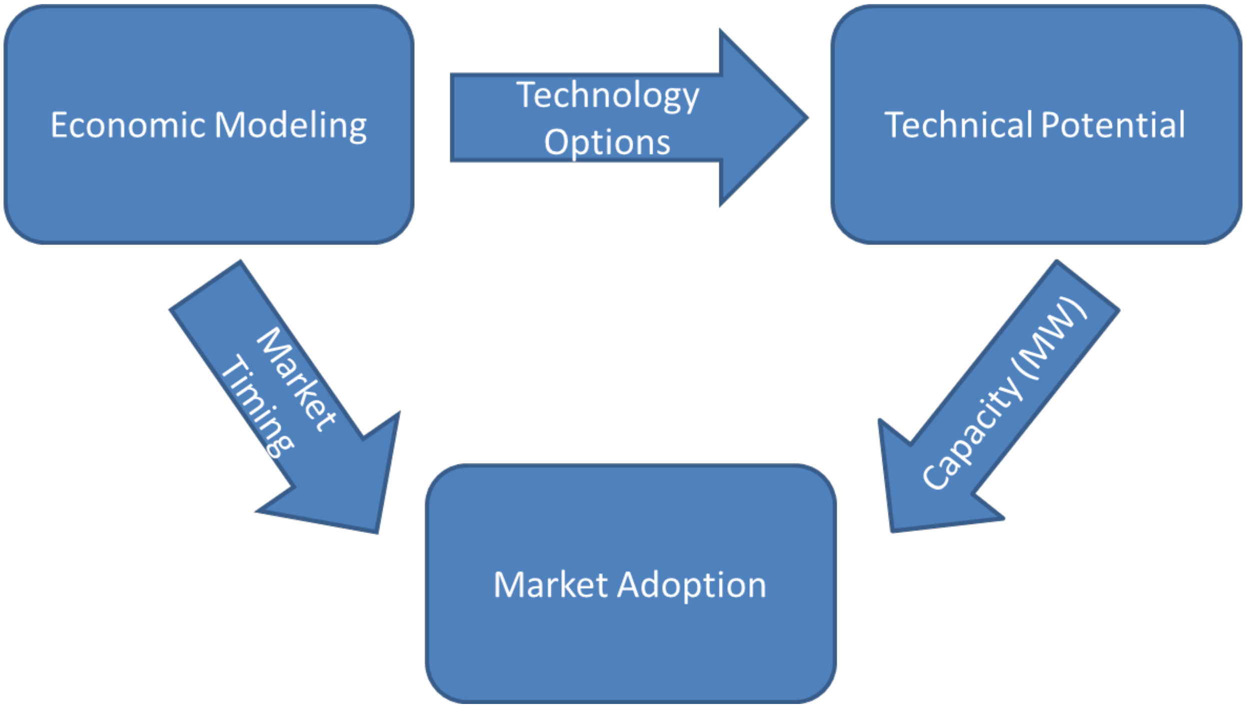
7.2 METHODOLOGY

The methodology used to forecast DG CHP relies on several key assumptions:

1) These systems will be installed as an investment decision to supply power to customers with the energy value modeled as equivalent offsetting retail purchases of electricity and natural gas used in boilers.
2) The CP-1 tariff's demand ratchet charge (currently $2/kW-month) offsets the $2/kW-month standby charge, enabling customers to offset retail energy and monthly demand charges with no further standby charges.
3) 100 percent of the energy production is used to offset retail purchases, with no electricity export.
4) Growth patterns through 2016 will reflect the presence of the federal ITC for select technologies.
5) Natural gas will be the fuel option.
6) Existing capacity is maintained or replaced at the same level of performance with the forecast reflecting incremental additions of CHP to energy capacity.
7) The performance of CHP in California reflects the potential performance of CHP in WPL's service territory.

To forecast the adoption of smaller scale CHP systems we completed three separate analyses. First, the economics of the technical options for six CHP technologies were estimated, with investment cost-effectiveness screening in investment options. Second, the technical potential for CHP was estimated in total and then assigned to the technologies that passed the economic screening. Third, the market adoption was estimated from the technical potential and then spread across the forecast period. The technical potential was analyzed by reviewing the electricity and natural gas loads of WPL's larger electricity customers. The base case reflects an adoption of cost-effective CHP technologies by a percentage of the technical potential. The low-policy case does not differ in economics from the base case, but reflects a slower adoption rate based on the price differential between CHP energy and the retail value of energy. The high-policy case is based on an assumed set of policy interventions that lowers capacity costs by 25 percent and with assumed higher market adoptions. Figure 7-1 illustrates the general flow of the CHP analysis and resulting market adoption forecast.

Figure 7-1. CHP Modeling Process



7.2.1 Economic modeling

In all CHP categories, we assume that financial returns drive investment decisions. To forecast future additions of CHP capacity, we developed an economic model to understand when, if, and in what policy context CHP may become cost effective in the forecast period.

In all categories, the basic economic model considers the levelized cost of energy (LCOE) compared to the assumed levelized value of energy (LVOE). Net natural gas expenses were included as a factor increasing the LCOE. For each year of the forecast period an LCOE for CHP and an energy value were developed, allowing for judgment of whether CHP may be attractive to develop. In years where the estimated value of energy would exceed the LCOE, we assume investments may occur. Table 7-3 describes the assumptions of the LCOE analysis.

We used various data sources and assumptions to establish LCOE for CHP. The primary sources of this information include the US EPA Catalog of CHP Technologies, regularly updated by the EPA CHP Partnership, and the California Public Utilities Commission (CPUC). These data sources establish typical size ranges in commercial operation across the US for each technology type. Accordingly, we selected technology sizes (nameplate capacity) near the typical upper and lower boundaries, supported by enough installations and commercial operating experience to establish credible values for capital and operating costs. We further checked against manufacturer product lines to be certain the target size units were available. These are blended to achieve national averages, which we used in this study. The LCOE is modeled assuming the lifespan of the given CHP technology (15 years or 20 years, depending on the technology). Table 7-3 summarizes the technology and financial assumptions underlying the CHP market.

Table 7-3. DG CHP LCOE Assumptions

DG CHP LCOE Factor	LCOE Metric						
	Fuel Cell		Gas Turbine		Internal Combustion Engine		Micro Turbine
System kW	300	1,400	2,900	5,280	500	1,500	200
Overnight capital cost ($/kW)	[redacted]						
Annual system MWh							
O&M cost ($/kW-yr)							
Marginal tax rate	35%	Assumed corporate tax rate					
MACRS NPV factor	0.288	Net present value factor of 5-year MACRS depreciation					
Discount rate	7.77%	Utility weighted average cost of capital, per WPL					
Inflation rate	[redacted]	Assumed general inflation rate, 2014–2029					

Performance factors for CHP are based on research conducted in California. The CPUC Self-Generation Incentive Program Cost-Effectiveness of Distributed Generation Technologies Final Report[42] shows that theoretical efficiencies for CHP have not been achieved in practice though may still show a net benefit from component heat and power energy sources. Our performance estimates for DG CHP in the WPL service territory is based on this experience and illustrated in Table 7-4.

[42] Itron, Inc. CPUC Self-Generation Incentive Program-Cost-Effectiveness of Distributed Generation Technologies Final Report; Submitted to: PG&E, February 9, 2011, Davis, CA.

Table 7-4. Performance Factors for CHP Technology

	Fuel Cell		Gas Turbine		ICE		Microturbine
Nameplate capacity (kW)	300	1,400	2,900	5,280	500	1,500	200
Annual performance degradation (%)[43]	[redacted]						
Electrical conversion efficiency (%), LHV)	[redacted]						
Thermal conversion efficiency (%), LHV)	[redacted]						
Heat recovered rate (mBtu/kWh generated)	[redacted]						
Fuel utilization or input (mmBtu/H)	[redacted]						
Recovered heat (MMBtu/yr)	[redacted]						
Boiler energy @ 80 percent efficiency	[redacted]						
NG CHP consumption (MMBtu per year)	[redacted]						

The base case and low-policy scenarios result in the same outcomes, with the high-policy case showing better financial performance for the calculated levelized cost of energy based on the assumed 25 percent reduction in capital costs. Table 7-5 and Table 7-6 present the estimated LCOE and LVOE for each year in the forecast period for each scenario.

[43] The annual performance degradation does not continue through the useful life of the technology. Rather, each five years a major overhaul is undertaken to bring the performance back to like-new operating conditions.

Table 7-5. Summary Table LCOE for CHP, Base and Low-Policy Support Cases ($/MWh)

Year	Fuel Cell		Gas Turbine		ICE		Micro Turbine
System kW	300	1,400	2,900	5,280	500	1,500	200
2014	[redacted]						
2015	[redacted]						
2016	[redacted]						
2017	[redacted]						
2018	[redacted]						
2019	[redacted]						
2020	[redacted]						
2021	[redacted]						
2022	[redacted]						
2023	[redacted]						
2024	[redacted]						
2025	[redacted]						
2026	[redacted]						
2027	[redacted]						
2028	[redacted]						
2029	[redacted]						

Table 7-6. Summary Table LCOE for CHP, High-Policy Support Case ($/MWh)

Year	Fuel Cell		Gas Turbine		ICE		Micro Turbine
System kW	300	1,400	2,900	5,280	500	1,500	200
2014	[redacted]						
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							

To estimate the value of energy against which the LCOE is compared, we developed an energy value component forecast using a general rate of inflation for electrical energy and demand, and natural gas using the variable components of current WPL industrial tariffs. For electrical energy consumption, on-peak CHP operations were assumed to occur 66 percent of the time, with off-peak occurring 33 percent of the time, allowing for the creation of a single blended value. Avoided demand charges were similarly forecasted, but applied as a positive net present value that reduced the LCOE. Natural gas prices were inflated by WPL's Wood Mackenzie wholesale price forecast[44], with the net present value applied as a negative value that increased the LCOE.

Table 7-7 describes the energy value against which the LCOE was compared.

[44] The natural gas wholesale price forecast was conducted by Wood Mackenzie. WPL provided this forecast to Tetra Tech for this study.

Table 7-7. CHP Summary Table—Estimated LVOE ($/MWh)

Year	15 Year	20 Year
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		

For all the technologies, increased natural gas expenses create a substantial burden for CHP economics. Of the CHP technologies, only the 1,500 kW ICE and 200 kW microturbine exhibit cost effectiveness during the forecast period. For the base case and low-policy case, the 1,500 kW ICE is cost effective in all years, with the 200 kW microturbine becoming cost effective in 2023. In the high-policy case, both technologies are cost effective in all years. The comparison of LCOE and LVOE is shown in Table 7-8 and Table 7-9 to illustrate the LCOE and LVOE differentials for these two respective technologies in each scenario.

Table 7-8. 1500 kW ICE LCOE and LVOE ($/MWh)

Year	Base Case		Low Policy Case		High Policy Case	
	LCOE	LVOE	LCOE	LVOE	LCOE	LVOE
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

Table 7-9. 200 kW Microturbine LCOE and LVOE ($/MWh)

Year	Base Case	Low Policy Case	High Policy Case
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			

7.2.2 Technical potential of CHP

WPL provided electrical energy and natural gas consumption information for customers with over $100,000 in annual electricity expenditures for WPL. From this list we selected possible CHP candidates by calculating the BTU ratio of gas to electricity consumption of at least 1:1 to ensure significant natural gas consumption. While some electric customers likely receive natural gas from utilities other than WPL, not all would be good CHP candidates. For customers without WPL gas consumption, we reviewed the customer's SIC code to estimate whether they were likely to be natural gas customers. Customers in food processing and institutional settings were added back into consideration. After screening for gas consumption and the BTU ratio and adding back likely large natural gas consumers, about half of the customer group remained as potential candidates (257 of 539).

To determine the potential CHP capacity that customers could potential adopt, we assumed a 65 percent load factor, applied to their annual kWh consumption. Sixty customers were found to be able to support 1,500 kW or more of CHP capacity, while 197 were found to be able to support 200 kW or more, but less than 1,500 kW. These two capacities were selected based on the economic modeling results (explained above).

For each potential CHP customer, their load was assigned multiples of either 1,500 kW or 200 kW, up to the point that their load would be met, but not exceeded by CHP capacity. Of the customers who could potentially support at least one 1,500 kW CHP unit, the 60 potential

CHP customers could support 3.0 MW of CHP, on average. For the customers assigned to the 200 kW CHP group, the 197 customers could support, on average 514 kW. The total CHP potential is estimated as 280 MW, with a mix of 1,500 kW and 200 kW individual units.

7.2.3 Market adoption of CHP

To estimate the market adoption, we reviewed findings from two EPRI studies of distributed energy in North America that investigated the market adoption rate for distributed energy, focusing primarily on CHP-type technologies.[45] Additionally, we calculated simple payback periods for the two CHP technologies that were found to be cost effective based on the economic model. The 1500 kW internal combustion engine system was found to maintain an approximate five-year simple payback through the forecast period, while the 200 kW microturbine maintained approximately a 7.5 year simple payback from 2023 through 2029.[46] The EPRI study segmented technically potential customers into “strong prospects, soft prospects, and no-prospects.” Simple payback investment criteria were one of several attributes that defined these segments. Strong prospects were considered “strong” due to being active in investigating CHP opportunities, while soft prospects were defined as having expressed a 50 percent or greater chance of investing within the next two years, but had not made any proactive efforts to investigate options. No-prospects were those customers not considered strong or soft prospects. We assume that this mix of attitudes from the EPRI reports are consistent with current WPL customer general attitudes and that, on average, technically potential CHP candidates reflect a mix of perspectives that represent investment decisions somewhat lower than the soft prospect attitudes and financial criteria.

The EPRI studies showed that with a five year simple payback, approximately 15 percent of soft prospects were likely to consider an investment. For projects with simple paybacks of six to ten years, less than 10 percent of customers would consider investing. Additional barriers cited in the report include risk perceptions related to equipment reliability, risk perceptions related to natural gas prices, and upper management being concerned primarily with non-energy investments. Given that the two CHP technologies that passed the economic screening showed a range of approximately a five- to seven-year simple payback in the base case and that risk perceptions and competition with non-energy investments may impact ultimate purchase behavior for CHP, we assumed for the base case and low-policy case adoption rates of 10 percent and 5 percent, respectively, of the technically potential CHP capacity.

For the high-policy case, capital costs are assumed to be 25 percent less. Simple paybacks reduce to about 3.5 years for the 1500 kW unit and about five years for the 200 kW microturbine. From the EPRI study, these simple paybacks align with a 30 percent and 20 percent investment rate for soft prospects. We discount the total adoption rate to an overall 20 percent for the high-policy case to account for risk perceptions and non-energy investment competition.

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[45] *Assessment of California CHP Market and Policy Options for Increased Penetration*. Electric Power Research Institute. April 2005.*Converting Distributed Energy Prospects Into Customers*. Electric Power Research Institute. December 2003.

[46] The 1500 kW ICE exhibited simple paybacks that dropped from 5 years in 2014 to 4.5 years in 2029. The 200 kW microturbine simple paybacks dropped from 7.8 to 7.4 years from 2023 to 2029 (2023 is the first year this CHP technology passes the cost effectiveness screening.

Adjusting for the scenario multiples results in the following CHP capacity adoptions that are applied to the CHP forecast over the 15-year forecast period.

Table 7-10. Cumulative New CHP Capacity Adoption, 2014–2029

Scenario	1,500 kW adoption (MW)	200 kW adoption (MW)	Total MW CHP by 2029
Base case	18	10	28
Low adoption	9	5	14
High adoption	36	20	56

To model adoptions, we assume that the forecasted market adoptions will all occur by 2029, with none occurring during 2014 (based on discussion with WPL staff of any known projects). Without knowing specific market conditions, we spread out the adoptions of each technology to reflect a steady market for the base case, a delayed market for the base case and low-policy case with acceleration in the market, and a gradually accelerating market for the high-policy case. Although the 1500 kW ICE is cost effective in 2014, no units were considered for adoption based on a lack of known projects by WPL as of April 2014. Table 7-11 explains the number of CHP units being forecasted for each scenario. Although the modeling presents results based on two technologies, the total results should be viewed as the estimate for CHP technology and not projections for the individual technologies.

Table 7-11. Forecast Model for CHP (numbers of units)

Year	Base Case		Low-Policy Case		High-Policy Case	
kW	200	1,500	200	1,500	200	1,500
2014	-	-	-	-	-	-
2015	-	-	-	-	2	1
2016	-	-	-	-	3	1
2017	-	-	-	-	4	1
2018	-	1	-	-	5	1
2019	-	1	-	-	5	1
2020	-	1	-	-	6	1
2021	-	1	-	-	6	2
2022	-	1	-	-	7	2
2023	4	1	-	-	7	2
2024	5	1	-	1	8	2
2025	6	1	3	1	8	2
2026	7	1	4	1	9	2
2027	8	1	5	1	9	2
2028	9	1	6	1	10	2
2029	11	1	7	1	11	3
Total units	50	12	25	16	100	25

The intent of the forecast for each scenario and technology is to generally show an increasing market for CHP, with steady adoptions gradually rising in terms of aggregate MW and MWh. The forecast is not meant to create specific findings or expectations regarding which CHP technology will be adopted, other than for years in which a technology may be not cost effective (with zero adoption).

7.3 RESULTS

In comparing the energy values to the LCOE estimates, only the 1,500 kW ICE and 200 kW microturbine are shown as being cost effective for customer investment purposes during the forecast period. The following tables present the results for total MW and MWh for CHP in each scenario. The results reflect cumulative additions of capacity and energy over and above what is currently interconnected with WPL.

Table 7-12. Base Case CHP Forecast

Year	Cumulative MW	Cumulative Summer Peak MW	Cumulative MWh
2014	-	-	-
2015	-	-	-
2016	-	-	-
2017	-	-	-
2018	1.5	1.4	4,625
2019	3	2.7	9,251
2020	4.5	4.1	13,876
2021	6	5.4	18,501
2022	7.5	6.8	23,126
2023	9.8	8.8	33,302
2024	12.3	11.1	44,865
2025	15	13.5	57,816
2026	17.9	16.1	72,154
2027	21	18.9	87,880
2028	24.3	21.9	104,994
2029	28	25.2	124,883

Table 7-13. Low-Policy Case CHP Forecast

Year	Cumulative MW	Cumulative Summer Peak MW	Cumulative MWh
2014	-	-	-
2015	-	-	-
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	-	-	-
2020	-	-	-
2021	-	-	-
2022	-	-	-
2023	-	-	-
2024	1.5	1.4	4,625
2025	3.6	3.2	13,413
2026	5.9	5.3	23,589
2027	8.4	7.6	35,152
2028	11.1	10.0	48,103
2029	14.0	12.6	62,441

Table 7-14 High-Policy Case CHP Forecast

Year	Cumulative MW	Cumulative Summer Peak MW	Cumulative MWh
2014	-	-	-
2015	1.9	1.7	7,400
2016	4.0	3.6	16,188
2017	6.3	5.7	26,364
2018	8.8	7.9	37,927
2019	11.3	10.2	49,490
2020	14.0	12.6	62,441
2021	18.2	16.4	80,017
2022	22.6	20.3	98,981
2023	27.0	24.3	117,945
2024	31.6	28.4	138,296
2025	36.2	32.6	158,647
2026	41.0	36.9	180,386
2027	45.8	41.2	202,125
2028	50.8	45.7	225,251
2029	57.5	51.8	254,390

Appendix 4B

Distributed Generation Study Addendum

(*Confidential information is marked gray*)

ADDENDUM

Wisconsin Power and Light

Distributed Generation Forecast Update

Introduction

Tetra Tech provided Wisconsin Power and Light (WPL) with a 16-year forecast of market driven distributed generation technology. The forecast was completed in September 2014 and based, in part, on market penetration of various distributed generation technologies through 2013. In Wisconsin, through September 2014, additions of solar electric systems that have been interconnected and the queue of potential solar electric projects that will possibly be interconnected by the end of 2014 exceeded the originally forecasted capacity additions. Through September 2014 the completed interconnections for 2014 were 18 percent higher than forecasted for the entire year. As a result, WPL requested that Tetra Tech update its forecast to include the actual 2014 solar electric installations interconnected through September 2014 and allow for a portion of the queue, or systems with interconnection applications awaiting project completion, to be included in the update. In addition to updating the solar forecast to account for 2014 actual and queued installations, Tetra Tech was asked to extend the forecast through 2042.

This addendum describes the additional modeling and results. First, we present the update to the solar forecast and describe the changes to the results through 2029, the original forecast period. Second, we describe the modeling employed to extend the forecast through 2042. Lastly, we present the results of the updated forecast for the entire forecast, accounting for the update to the solar forecast and extension of the forecast period.

Solar Forecast Update

Tetra Tech received from WPL data describing the solar electric interconnections through September 2014. Additionally, WPL provided data that showed the systems in the interconnection queue. The queue represents systems that had applied for eventual interconnection but had not yet been installed or interconnected. With the exception of one system, all installed solar electric systems were of the net metered variety. The exception was a single 39 kW system.

The original forecast did not allow for additional non-net metered systems to be installed, as modeling results deemed them to be uneconomic. As only one system in this size range was installed and the queue indicated no additional systems in this size range, we assume that the customer decision making process was based on a situation that could not be forecasted. Nevertheless, to account for that system in the total forecast, the additional capacity was added to the updated forecast.

The data indicated that for net metered systems (20 kW and less), a total of 159 kW had been installed through September 2014. The total kW of systems in the queue were all net metered systems and totaled 176 kW. One 5 kW queued system was removed from the total due to having been in the queue since late 2011, with this customer having subsequently installed a 20 kW system, suggesting that the 5 kW system may not ultimately be installed. All other systems in the queue had applications dating from late 2012 through September 2014. By removing the single 5 kW system, the result is an assumed project queue of 171 kW that could theoretically be installed in 2014.

The queue was utilized to account for interconnections that would occur after September 2014, but within the 2014 calendar year. The specific disposition of each project was not ultimately known, but it is reasonable to assume that some portion of the queued projects would not be installed in the calendar year. Given the length of time in the queue, WPL's experience with solar interconnections in prior years occurring in the last quarter of the year, and past experience indicating the capacity of the market to complete the capacity in the queue, Tetra Tech assumed that 60 percent of the queue would be installed—103 kW. The 103 kW is within the range of past fourth quarter installations (ranging from 27 kW in 2012 to 216 kW in 2011) but also allows for a market that has fluctuated over the last several years.

Table A-1 summarizes the 2014 capacity that was used to update the WPL solar electric forecast using 2014 actual and queued interconnections.

Table A-1. Nameplate Capacity kW (DC)

Segment	Installed	Queue	60% of Queue	Total for Forecast[1]
Net-metered (20 kW and less)	159 kW	171 kW	103 kW	262 kW
Non-net-metered (>20 kW)	39 kW	0 kW	0 kW	39 kW
Total Estimated kW for 2014	198 kW	171 kW	103 kW	301 kW

To update the solar electric forecast and ultimately the aggregate distributed generation forecast, the estimated 2014 interconnected kW from Table A-1 were utilized as the assumed kW for 2014. In the case of non-net-metered systems, the additional 39 kW simply added 39 kW to the installed base of systems less than 100 kW and greater and 20 kW. Systems of this size are not expected to be economic for the owners or have forecasted capacity additions until 2022 in the base case scenario.

For net metered systems, the estimated 2014 capacity of 262 kW is assumed for that year and has an impact on subsequent years' capacity additions. For net metered systems, growth percentages on the cumulative capacity are utilized to forecast each year's additional solar electric capacity. Starting with 2014, the cumulative capacity is higher than originally forecast, which increases the subsequent years' cumulative capacity over the original forecast as the percentage increase is calculated from a higher base. For example, if a year was forecasted to grow by 10 percent, the absolute capacity growth is higher for a year with 2,000 kW of cumulative capacity than a year with 1,000 kW of cumulative capacity (200 kW vs. 100 kW). Other than for 2014, all other modeling assumptions used in the original forecast were kept the same as described in Section 4.2 of the original forecast report.

[1] The total represents the sum of the 2014 installed systems and 60 percent of the remaining queue. Specific system capacity may differ due to rounding.

For illustrative purposes, Table A-2 shows the effect of the changes over time for the base case solar electric portion of the distributed generation forecast. The detailed results for each scenario are presented in the subsequent tables describing the aggregate forecast adjustments. The effect of using the updated 2014 estimates shows a significant percentage increase in the updated forecast early in the forecast period, but much less of a percentage increase later in the forecast period. The main reason for the dampened effect later in the forecast period is the growth from non-net-metered systems starting in 2022, which were not affected by the forecast update, other than the addition of the single 39 kW system.

Table A-2. Interconnected Solar Electric Capacity Forecast Comparison, Base Case

Year	Original Forecast Cumulative New Solar Capacity (MW)	Updated Forecast Cumulative New Solar Capacity (MW)
2014	0.134	0.301
2015	0.276	0.450
2016	0.427	0.609
2017	0.443	0.626
2018	0.461	0.646
2019	0.486	0.672
2020	0.516	0.704
2021	0.551	0.741
2022	1.009	1.200
2023	1.523	1.716
2024	2.098	2.294
2025	3.320	3.519
2026	4.683	4.884
2027	6.208	6.412
2028	7.922	8.131
2029	9.832	10.044

Extending the Forecast to 2042

The original forecast covered the 2014 through 2029 time period. WPL requested that the forecast be extended to 2042. The modeling method used to extend the forecast differed substantially from the initial forecast. The initial forecast used a combination of past market behavior, technological performance, economic modeling, and an Energy Information Administration (EIA) forecast. As years beyond 2029 had limited information regarding these factors, Tetra Tech selected a more generalized approach to forecasting 2030 to 2042 distributed generation.

Four general approaches were used. First, for a market under which the original forecast indicated market saturation or for which systems did not exhibit positive economics, no additional capacity was added to the forecast. That trend was extended to 2042. Second, where Energy Information Administration forecasts were used in the original forecast, those forecasts were used and extended to 2042, and applied in the same manner as the original forecast. Third, a linear approach to forecast extensions were used for farm biogas in the high policy scenario, in-line with the approach taken in the original forecast. Finally, for several solar and wind market cases, a general logistic model was used to extend the forecast through 2042 and is described in more detail in the subsequent paragraphs.

A general logistic function describes an s-shaped curve and has been used to describe the diffusion of innovation for many types of markets. In utilizing that technique for extending the WPL distributed generation forecast, the approach is implicitly applying the curve as a market diffusion model. In this model the 2014–2029 forecast is assumed to represent the initial market diffusion of distributed generation, with the logistic function used to represent and cap the market diffusion from 2030 through 2042. The approach assumes that the original forecast describes 50 percent market saturation by 2029, with the remaining 50 percent achieved by approximately 2042.

This general approach to market diffusion of energy innovations has been described by the National Renewable Energy Laboratory[2], with a number of approaches that result in an s-shaped curve to represent market diffusion. This approach assumes no supply side restrictions that would inhibit market growth other than the assumed market capacity limit. In that regard, the approach for the 2030 to 2042 forecast aligns with the 2014–2029 forecast in assuming no fundamental barriers exist that would cap market expansion to the modeled maximum. Additionally, Tetra Tech urges some caution at assuming the specific capacity additions are applicable to a given year—the logistic model is an abstraction of market diffusion that captures a general trend, not necessarily appropriate for modeling a specific effect for a specific point in time.

The general logistic function is described as[3]:

$$P(t) = \frac{KP_0 e^{rt}}{K + P_0(e^{rt} - 1)}$$

In this function, K represents the target saturation level (cumulative MW for purposes of the forecast). P_0 represents the initial population, assumed to be the cumulative MW in 2029 from the forecast and representing the 50 percent market saturation level. “r” represents the rate of growth and is modeled as the growth rate from 2028 to 2029 for each technology segment. “t” represents the number of years from the initial population. For example, in 2030, “t”=1, whereas in 2042, “t=13.”

[2] Packey, Daniel J, *Market Penetration of New Energy Technologies.* National Renewable Energy Laboratory. 1993.

[3] Lombaert, et al. *Dispersal Strategies of Phytophagous Insects at a Local Scale: Adaptive Potential of Aphids in an Agricultural Environment.* BMC Evolutionary Biology. 2006, 6:75. Online: http://www.biomedcentral.com/1471-2148/6/75

As the initial condition (P_0) is assumed to represent 50 percent of market saturation, the s-shaped curve of the logistic function is only using the latter half of the logistic curve. The latter half of the curve is at the inflection point, or the point at which the curve's rate of growth starts to decrease. As such, the use of the logistic function enables the distributed generation forecast to "bend the curve" toward an asymptote at the point of market saturation. If P_0 were used to represent a point of zero market penetration, the shape of the diffusion would be the full s-shaped curve. However, in that case, the question is begged of how to identify the capacity of the market and rate of growth—two issues that utilizing the 2014–2029 forecasts to set the saturation points and growth rates solve.

Table A-3, below, describes the approach used for extending the forecast from 2030 through 2042.

Table A-3. Forecast Extension Approach by Technology and Scenario

Technology Segment	Base Case	High Policy Case	Low Policy Case
Solar			
Net metered	EIA AEO 2013 reference case growth % through 2040; 2039 to 2040 % growth thereafter	EIA AEO 2013 no sunset case through 2040; 2039 to 2040 % growth thereafter	Same as base case, with growth rate at 25% of base case
Non-net metered	Logistic model	Logistic model	Logistic model
Wind			
Net metered	Half of net-metered solar growth	Half of net-metered solar growth	Half of net-metered solar growth
Non-net metered customer sited	Zero additions	Zero additions	Zero additions
MW-class	Logistic model	Logistic model	Logistic model
Biogas			
Wastewater Treatment Plants	Zero additions	Zero additions	Zero additions
Farm	Zero additions	290 kW added each year	Zero additions
Combined Heat & Power			
All CHP	Zero additions	Zero additions	Zero additions

As described above, some markets with zero additions to the extended forecast either did not exhibit positive economics or had been assumed to reach a market saturation. For wind markets with zero additions, these markets and scenarios were uneconomic per the original forecast. The same is true for farm biogas technologies. In contrast, combined heat and power technology and wastewater treatment plant biogas technology were assumed to have reached a market saturation in the original forecast.

Updated Forecast Results

The original forecast covered 2014 through 2029. Of the changes made to the forecast, only the update to the solar electric market altered the forecast in this time period. The following tables describe the changes for the solar electric market through 2029 for each scenario and then present the aggregate forecast results for all technologies through 2042 for each scenario.

For the updated solar forecast, the additional solar electric capacity added in 2014 is approximately double the capacity originally forecasted. The effect on the capacity and associated energy production by 2029 is only an increase of approximately 2 percent compared to the original forecast. The reason is that the significant growth in the solar electric market in later forecast years is driven by non-net-metered systems, which were unaffected by the updated 2014 installation estimate (actual and queued) other than the 39 kW system that was installed in 2014.

Table A-4. Base Case Updated Forecast Distributed Solar PV WPL 2014–2029[4]

Year	Total Cumulative Additional MW	Associated Annual MWh	Associated Summer Peak MW
2014	0.30	370	0.11
2015	0.45	555	0.16
2016	0.61	750	0.22
2017	0.63	771	0.23
2018	0.65	795	0.23
2019	0.67	827	0.24
2020	0.70	866	0.25
2021	0.74	912	0.27
2022	1.20	1,478	0.43
2023	1.72	2,113	0.62
2024	2.29	2,825	0.82
2025	3.52	4,334	1.27
2026	4.88	6,015	1.76
2027	6.41	7,897	2.31
2028	8.13	10,013	2.92
2029	10.04	12,370	3.61

[4] For solar electric technology, gross MW is included on a DC basis. For solar electric MWh and Summer Peak MW, and for all other technologies, results are in AC.

Table A-5. Low Policy Case Updated Forecast Distributed Solar PV WPL 2014–2029

Year	Total Cumulative Additional MW	Associated Annual MWh	Associated Summer Peak MW
2014	0.30	370	0.11
2015	0.45	555	0.16
2016	0.61	750	0.22
2017	0.61	756	0.22
2018	0.62	761	0.22
2019	0.62	769	0.22
2020	0.63	779	0.23
2021	0.64	790	0.23
2022	0.65	801	0.23
2023	1.13	1,396	0.41
2024	1.67	2,061	0.60
2025	2.86	3,520	1.03
2026	4.18	5,150	1.50
2027	5.66	6,976	2.04
2028	7.33	9,023	2.63
2029	9.18	11,311	3.30

Table A-6. High Policy Case Updated Forecast Distributed Solar PV WPL 2014–2029

Year	Total Cumulative Additional MW	Associated Annual MWh	Associated Summer Peak MW
2014	0.30	370	0.11
2015	0.45	555	0.16
2016	0.61	750	0.22
2017	1.05	1,292	0.38
2018	1.77	2,174	0.63
2019	2.52	3,105	0.91
2020	3.41	4,206	1.23
2021	4.72	5,812	1.70
2022	6.11	7,529	2.20
2023	7.62	9,387	2.74
2024	9.25	11,392	3.33
2025	11.02	13,570	3.96
2026	12.93	15,921	4.65
2027	16.34	20,120	5.87
2028	20.08	24,734	7.22
2029	24.21	29,812	8.70

The results for the aggregate distributed generation forecast are presented below. Table A-7 is the original summary table from the forecast, with Table A-8 presenting the extended forecast and incorporating the solar electric update. Table A-8 replaces Table 2-2 in the original report. Changes to the forecast from 2014–2029 are due solely to the solar update, with the years beyond 2029 new to the forecast.

Table A-7. Cumulative Additional Distributed Generation, WPL 2014–2029 (ORIGINAL)

Year	Gross MW[5]			Summer Peak MW			Associated MWh		
Scenario	Base	High	Low	Base	High	Low	Base	High	Low
2014	0.15	0.15	0.15	0.05	0.05	0.05	186	186	186
2015	0.32	2.22	0.32	0.11	1.82	0.11	384	7,784	384
2017	0.51	8.36	0.50	0.17	6.14	0.16	917	30,097	599
2020	5.10	22.88	0.52	4.25	15.12	0.17	14,594	83,706	625
2025	18.63	61.47	6.55	14.89	40.13	4.39	63,595	217,599	18,359
2029	41.94	101.54	23.28	29.47	65.67	16.03	147,464	348,890	75,182

Table A-8. Cumulative Additional Distributed Generation, WPL 2014–2042 (UPDATE)

Year	Gross MW[6]			Summer Peak MW			Associated MWh		
Scenario	Base	High	Low	Base	High	Low	Base	High	Low
2014	0.32	0.32	0.32	0.11	0.11	0.11	392	392	392
2015	0.49	2.39	0.49	0.17	1.88	0.17	599	7,999	599
2017	0.69	8.56	0.68	0.23	6.22	0.23	843	30,350	825
2020	5.28	23.16	0.70	4.31	15.22	0.24	14,825	84,051	851
2025	18.83	61.90	6.73	14.96	40.28	4.46	63,840	218,126	18,589
2029	42.15	102.09	23.47	29.54	65.87	16.09	153,527	349,567	75,416
2035	52.62	125.67	29.62	32.47	73.83	18.30	164,705	397,048	82,995
2040	55.61	141.53	31.81	33.53	78.76	19.09	168,876	433,618	85,682
2042	56.36	147.64	32.22	33.79	80.55	19.23	169,307	448,422	86,182

The extended forecast from 2030 to 2042 shows slowing growth in the distributed generation market. New additions occur in the solar and wind markets for all scenarios, with biogas adding capacity in the high policy scenario. Differences in 2029 due to the 2014 adjustment to solar electric systems shows an increase of approximately 200 kW in gross capacity. For other technologies, market saturation is assumed in 2029. The result is that the 2030–2042 timeframe is projected to increase gross capacity from 2029 by approximately 35 percent for the base and low policy scenarios and by 16 percent for the high policy scenario. Capacity percentage growth is higher for the base and low policy scenarios as solar electric systems are projected to drive most of the additional capacity (along with MW-class wind). In the high policy case, biogas and combined heat and power (CHP) technologies add capacity prior to 2030 but not in subsequent years. As a result, the growth rate is dampened relative to other cases due to the higher base from which to grow.

[5] For solar electric technology, gross capacity (MW) is included on a DC basis. For solar electric energy (MWh) and Summer Peak capacity (MW), and for all other technologies, results are in AC terms.
[6] For solar electric technology, gross capacity (MW) is included on a DC basis. For solar electric energy (MWh) and Summer Peak capacity (MW), and for all other technologies, results are in AC terms.

We urge some caution at utilizing the specific capacities, MWh, and timing of capacity additions as expressed in the forecast. The *general* timing and direction of capacity and MWh may be a more appropriate use of the data. Further, unforeseen technology and policy changes may shift the opportunities and underlying economics of each technology. Such a change could drive shifts between technology preferences by the market, expanding or contracting individual technology markets. Further, as distributed generation grows, constraints on the distribution and transmission system may limit specific projects that would otherwise go forward, causing a shift in market choices. Finally, additional technology opportunities may emerge that were not included in the original forecast.

Appendix 4C

Distributed Generation Summary Table

(*Does not contain confidential information*)

Public Version

Base Case Scenario: Distributed Generation Projections by Technology for Wisconsin Power and Light Territory, 2014-2042

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Solar (<100 kW)															
Nameplate MW (DC)	0.30	0.45	0.61	0.63	0.65	0.67	0.70	0.74	1.20	1.72	2.29	2.94	3.66	4.46	5.36
Summer demand impact MW (AC)	0.11	0.16	0.22	0.23	0.23	0.24	0.25	0.27	0.43	0.62	0.82	1.06	1.31	1.60	1.93
Annual MWH	370	555	750	771	795	827	866	912	1,478	2,113	2,825	3,620	4,501	5,488	6,602
Solar (>100 kW)															
Nameplate MW (DC)	-	-	-	-	-	-	-	-	-	-	-	0.58	1.23	1.96	2.77
Summer demand impact MW (AC)	-	-	-	-	-	-	-	-	-	-	-	0.21	0.44	0.70	1.00
Annual MWH	-	-	-	-	-	-	-	-	-	-	-	714	1,513	2,409	3,411
Wind (Customer Sited)															
Nameplate MW	0.02	0.04	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12	0.13
Summer demand impact MW	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Annual MWH	21	44	68	71	74	78	83	88	93	99	106	113	120	128	137
Wind (MW-Class)															
Nameplate MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.84
Summer demand impact MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.26
Annual MWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,276
Combined Heat and Power															
Nameplate MW	-	-	-	-	1.50	3.00	4.50	6.00	7.50	9.80	12.30	15.00	17.90	21.00	24.30
Summer demand impact MW	-	-	-	-	1.35	2.70	4.05	5.40	6.75	8.82	11.07	13.50	16.11	18.90	21.87
Annual MWH	-	-	-	-	4,625	9,251	13,876	18,501	23,126	33,302	44,865	57,816	72,154	87,880	104,994
Landfill Gas															
Nameplate MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Summer demand impact MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual MWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biogas															
Nameplate MW	-	-	-	-	-	-	-	0.10	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Summer demand impact MW	-	-	-	-	-	-	-	0.09	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Annual MWH	-	-	-	-	-	-	-	788	1,577	1,577	1,577	1,577	1,577	1,577	1,577
Total Distributed Generation															
Nameplate MW	0.32	0.49	0.67	0.69	2.22	3.75	5.28	6.92	8.99	11.81	14.90	18.83	23.10	27.74	34.60
Summer demand impact MW	0.11	0.17	0.23	0.23	1.59	2.95	4.31	5.77	7.37	9.63	12.09	14.96	18.06	21.40	25.25
Annual MWH	392	599	819	843	5,495	10,156	14,825	20,289	26,275	37,092	49,373	63,840	79,866	97,482	120,996
Total Distributed Generation - Including Transmission Efficiency Gain															
Nameplate MW	0.33	0.51	0.69	0.71	2.28	3.85	5.42	7.11	9.23	12.13	15.30	19.33	23.72	28.48	35.53
Summer demand impact MW	0.11	0.17	0.23	0.24	1.63	3.03	4.43	5.92	7.57	9.89	12.41	15.36	18.55	21.98	25.93
Annual MWH	399	611	835	859	5,603	10,355	15,115	20,687	26,789	37,818	50,340	65,090	81,429	99,390	123,365

Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Solar (<100 kW)														
Nameplate MW (DC)	6.36	7.04	7.72	8.38	9.02	9.61	10.17	10.69	11.16	11.60	12.00	12.35	12.68	12.98
Summer demand impact MW (AC)	2.29	2.53	2.78	3.01	3.24	3.45	3.66	3.84	4.01	4.17	4.31	4.44	4.56	4.66
Annual MWH	7,836	8,675	9,511	10,325	11,104	11,835	12,524	13,165	13,747	14,281	14,772	15,212	15,613	15,980
Solar (>100 kW)														
Nameplate MW (DC)	3.68	4.29	4.87	5.40	5.85	6.23	6.53	6.77	6.95	7.09	7.19	7.27	7.32	7.36
Summer demand impact MW (AC)	1.32	1.54	1.75	1.94	2.10	2.24	2.35	2.43	2.50	2.55	2.59	2.61	2.63	2.65
Annual MWH	4,533	5,285	6,000	6,648	7,208	7,673	8,047	8,339	8,563	8,731	8,857	8,949	9,017	9,067
Wind (Customer Sited)														
Nameplate MW	0.14	0.15	0.16	0.17	0.18	0.19	0.20	0.21	0.22	0.23	0.25	0.26	0.27	0.29
Summer demand impact MW	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Annual MWH	146	155	165	175	185	195	206	218	231	244	258	272	286	300
Wind (MW-Class)														
Nameplate MW	3.77	5.58	6.71	7.22	7.42	7.49	7.52	7.53	7.53	7.53	7.53	7.53	7.53	7.53
Summer demand impact MW	0.53	0.79	0.95	1.02	1.05	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06
Annual MWH	8,750	12,952	15,580	16,774	17,239	17,408	17,468	17,489	17,497	17,499	17,500	17,501	17,501	17,501
Combined Heat and Power														
Nameplate MW	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
Summer demand impact MW	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20	25.20
Annual MWH	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883	124,883
Landfill Gas														
Nameplate MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Summer demand impact MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual MWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biogas														
Nameplate MW	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Summer demand impact MW	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Annual MWH	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577	1,577
Total Distributed Generation														
Nameplate MW	42.15	45.26	47.66	49.37	50.67	51.72	52.62	53.40	54.07	54.65	55.17	55.61	56.01	56.36
Summer demand impact MW	29.54	30.26	30.88	31.38	31.80	32.16	32.47	32.75	32.99	33.19	33.37	33.53	33.67	33.79
Annual MWH	147,725	153,527	157,715	160,381	162,195	163,571	164,705	165,671	166,497	167,215	167,847	168,394	168,876	169,307
Total Distributed Generation - Including Transmission Efficiency Gain														
Nameplate MW	43.28	46.47	48.94	50.69	52.03	53.11	54.03	54.83	55.52	56.12	56.65	57.10	57.51	57.87
Summer demand impact MW	30.33	31.07	31.70	32.22	32.65	33.02	33.34	33.63	33.87	34.08	34.27	34.43	34.57	34.70
Annual MWH	150,617	156,532	160,802	163,521	165,370	166,773	167,929	168,914	169,756	170,489	171,133	171,690	172,182	172,621

note: generation including transmission efficiency gain reflects the energy production that would otherwise be required from a central station plant and subject to transmission system efficiency losses.

Appendix 5A

WPL Generating Units

(*Does not contain confidential information*)

Table 5.1.2 WPL 2014 IRP, WPL's Existing Generating Units: Installed Emission Controls and CAMP Projects.

Resource in Order of Appearance in EGEAS	EGEAS Unit Name	2013 Summer Reserve Capacity (ZRC)	Fuel or Motive Force for Noncombustible Resources	Installed AQCS: Nitrogen Oxide Controls	Installed AQCS: Sulfur Dioxide Controls	Installed AQCS: Particulate Matter Controls	Installed AQCS: Mercury Controls	Major* Comprehensive Asset Management Programs (CAMP) Completed by 12/31/2014
Supply-Side Resources								
Top of Iowa 1 (Worth)	TOIA X	4.4	Wind					
Forward II	FENA X	3.4	Wind					
Cristal Lake 2**	CL1A X		Wind					
Monfort	EDNA X	0.4	Wind					
Petenwell Hydro	WRHY X	10.1	Hydro					
Castle Rock	WRHY X	8.8	Hydro					
Juneau/Petenwell CT	WRCT X	4.7	Fuel Oil					
Kilbourn	WPHY X	6.2	Hydro					
Prairie du Sac 1	WPHY X	14.1	Hydro					
Cedar Ridge	CEDR X	7.9	Wind					
Bent Tree**	BENT C		Wind					
Rock River 3	ROR3 X	23.3	Natural Gas					
Rock River 4	ROR4 X	13.6	Natural Gas					
Rock River 5	ROR5 X	47.9	Natural Gas					
Rock River 6***	ROR6 X		Natural Gas					
Sheepskin 1	SIN1 X	32.9	Natural Gas					
South Fond Du Lac 2	SFL2 X	71.6	Natural Gas & Oil					
South Fond Du Lac 3	SFL3 X	71.3	Natural Gas & Oil					
Sheboygan Falls 1	SBN1 X CT	140.3	Natural Gas					
Sheboygan Falls 2	SBN2 X CT	141.7	Natural Gas					
Neenah CT1	NEN1 X CT	134.7	Natural Gas					
Neenah CT2	NEN2 X CT	144.0	Natural Gas					
Riverside	RIV X	568.3	Natural Gas	SCR, LNC				
Edgewater 3	EDG3 X R15	54.3	Coal	OFA, RRI, & SNCR	LSC	ESP w/ FGC		
Edgewater 4	EDG4 X E4R18	210.5	Coal	OFA, RRI, & SNCR	LSC	ESP w/ FGC	CaBr2	
Edgewater 5	EDG5 X E4R18	402.1	Coal	LNB, OFA, & SCR	LSC	ESP	ACI & CaBr2	
Columbia Unit 1	COL1 X 3538	255.7	Coal	LNB, OFA, NN	LSC & FGD	ESP w/ FGC & BH	ACI & CaBr2	Cooling Towers
Columbia Unit 2	COL2 X 3538	248.4	Coal	LNB, OFA, NN	LSC & FGD	ESP w/ FGC & BH	ACI & CaBr2	Cooling Towers
Nelson Dewey 1	NED1 X R15	104.0	Coal	OFA, RRI, & SNCR	LSC	ESP	CyClean A & B	
Nelson Dewey 2	NED2 X R15	103.0	Coal	OFA, RRI, & SNCR	LSC	ESP	CyClean A & B	
Total Supply-Side ZRCs		2,827.6						
Demand Resources:								
Interruptible Load	DINT X	147.2						
Supply Purchases & Sales****		(105.0)						
Total ZRCs		2,869.8						
Energy Only Resources								
Kewaunee PPA*****	KNPP C LY2013		Nuclear					
Morgan Stanley Power	MSCG C On Pk14		On-Peak					
Morgan Stanley Power	MSCG C Off Pk14		Off-Peak					
Morgan Stanley Power	MSCG C On Pk1518		On-Peak					
Morgan Stanley Power	MSCG C Off Pk1518		Off-Peak					
Northern States Power Co.	NSPR C RTC1415		Around the clock					
Economy Purchases RTC	ERTC		Around the clock					
Economy Purchases OPK	EOPK		Peaking					

* "Major" is defined as projects requiring a PSCW Certificate of Authority to construct.
** Crystal Lake & Bent Tree have zero capacities in PY 2013/14 reflecting provisional interconnection service awaiting transmission upgrades.
*** Rock River Unit 6 has a zero capacity in PY 2013/14 because it was not returned to service in time for a GVTC after an equipment failure.
**** Modeled in EGEAS ORT as ZRC transfers.
***** PPA expired at the end of 2013, modeled in EGEAS as an energy-only resource in 2013.

Key to installed AQCS (Air Quality Control System) acronyms

System	Description	System	Description
ACI	Activated Carbon Injection	LNB	Low NOx Burners
BH	Bag House	LSC	Low Sulfur Coal
CaBr2	Calcium Bromide	NN	Neural network boiler system optimization
CyClean A & B	Fluxing and liquid coal pre-treatments	OFA	Over-fire air
ESP	Electrostatic Precipitator	RRI	Rich Regent Injection
FGC	Flue Gas Conditioning with SO3	SCR	Selective Catalytic Reduction
FGD	Flue Gas Desulfurization	SNCR	Selective Noncatalytic Reduction
LNC	Low NOx Combustors		

Appendix 5B

WPL Generating Unit Data Sheets

(*Confidential information is marked gray*)

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

Rock River 3	ROR3 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.				[redacted]																													
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			27.00																														
	Operating	MW			27.00																														
	Emergency	MW			23.30																														
	Reserve	MW			23.30	23.30	25.10	25.10	25.10	25.10	25.10	25.10	0.00																						
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0772						0.0000																						
Emission Rates																																			
	SO2	Tons/Ton of fuel			5.20E-05																														
	NOX	Tons/Ton of fuel			3.50E-04																														
	CO2	Tons/Ton of fuel			9.15E-02																														
	CO	Tons/Ton of fuel			3.80E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			3.50E-04																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Public Version

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Rock River 4	ROR4 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			15.00																														
	Operating	MW			15.00																														
	Emergency	MW			13.60																														
	Reserve	MW			13.60	13.60	13.30	13.30	13.30	13.30	13.30	13.30	0.00																						
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	0.9779						0.0000																						
Emission Rates																																			
	SO2	Tons/Ton of fuel			2.70E-07																														
	NOX	Tons/Ton of fuel			1.48E-04																														
	CO2	Tons/Ton of fuel			4.96E-02																														
	CO	Tons/Ton of fuel			3.80E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			1.48E-04																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Public Version

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

Rock River 5	ROR5 X	Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			51.00																														
	Operating	MW			51.00																														
	Emergency	MW			47.90																														
	Reserve	MW			47.90	47.90	49.23	49.23	49.23	49.23	49.23	49.23	49.23	49.23	49.23	0.00																			
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No		1.0000	1.0000	1.0277									0.0000																			
	Reserve	MW																																	
Emission Rates																																			
	SO2	Tons/Ton of fuel			3.00E-05																														
	NOX	Tons/Ton of fuel			3.40E-05																														
	CO2	Tons/Ton of fuel			5.30E-02																														
	CO	Tons/Ton of fuel			3.80E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			3.34E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

Rock River 6	ROR6 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			44.75																														
	Operating	MW			44.75																														
	Emergency	MW			20.00																														
	Reserve	MW			20.00			20.00	38.00	49.00	49.00	49.00	49.00	49.00	49.00	0.00																			
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			0.0000	0.0000	0.0000	1.0000	1.9000	2.4500						0.0000																			
Emission Rates																																			
	SO2	Tons/Ton of fuel			3.00E-05																														
	NOX	Tons/Ton of fuel			2.22E-04																														
	CO2	Tons/Ton of fuel			5.30E-02																														
	CO	Tons/Ton of fuel			3.80E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			2.22E-04																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Public Version

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Sheepskin 1	SIN1 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.				[redacted]																													
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			38.00																														
	Operating	MW			38.00																														
	Emergency	MW			32.90																														
	Reserve	MW			32.90	32.90	34.90	34.90	34.90	34.90	34.90	34.90	0.00																						
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0607						0.0000																						
Emission Rates																																			
	SO2	Tons/Ton of fuel			3.00E-05																														
	NOX	Tons/Ton of fuel			3.50E-04																														
	CO2	Tons/Ton of fuel			5.30E-02																														
	CO	Tons/Ton of fuel			3.00E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			3.50E-04																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Public Version

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
South Fond Du Lac 2	SFL2 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.				[redacted]																													
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			85.00																														
	Operating	MW			85.00																														
	Emergency	MW			71.60																														
	Reserve	MW			71.60	71.60	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	69.90	0.00							
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	0.9763																					0.0000							
Emission Rates																																			
	SO2	Tons/Ton of fuel			3.00E-07																														
	NOX	Tons/Ton of fuel			4.10E-05																														
	CO2	Tons/Ton of fuel			5.95E-02																														
	CO	Tons/Ton of fuel			5.70E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			4.10E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
South Fond Du Lac 3	SFL3 X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator							[redacted]																												
Variable Operations and Maintenance Costs		$/MWH					[redacted]																												
EGEAS-Type Escalator							[redacted]																												
Full Load Heat Rate		BTU/kWh			[redacted]		[redacted]																												
	Trajectory		No																																
Capacities																																			
	Rated	MW			85.00																														
	Operating	MW			85.00																														
	Emergency	MW			71.30																														
	Reserve	MW			71.30	71.30	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	72.60	0.00							
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0182																					0.0000							
Emission Rates																																			
	SO2	Tons/Ton of fuel			2.60E-07																														
	NOX	Tons/Ton of fuel			3.50E-05																														
	CO2	Tons/Ton of fuel			5.95E-02																														
	CO	Tons/Ton of fuel			5.70E-05																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			3.50E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Sheboygan Falls 1	SBN1 X CT																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator							[redacted]																												
Variable Operations and Maintenance Costs		$/MWH					[redacted]																												
EGEAS-Type Escalator							[redacted]																												
Full Load Heat Rate		BTU/kWh			[redacted]		[redacted]																												
	Trajectory		No				[redacted]																												
Capacities																																			
	Rated	MW			150.00																														
	Operating	MW			150.00																														
	Emergency	MW			140.30																														
	Reserve	MW			140.30	140.30	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88	140.88
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0042																												
Emission Rates																																			
	SO2	Tons/Ton of fuel			1.20E-07																														
	NOX	Tons/Ton of fuel			1.70E-05																														
	CO2	Tons/Ton of fuel			1.04E-01																														
	CO	Tons/Ton of fuel			1.00E-06																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			2.30E-06																														
	ONOX	Tons/Ton of fuel			1.70E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Sheboygan Falls 2	SBN2 X CT																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			150.00																														
	Operating	MW			150.00																														
	Emergency	MW			141.71																														
	Reserve	MW			141.71	141.71	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80	138.80
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	0.9795																												
Emission Rates																																			
	SO2	Tons/Ton of fuel			1.20E-07																														
	NOX	Tons/Ton of fuel			1.60E-05																														
	CO2	Tons/Ton of fuel			9.01E-02																														
	CO	Tons/Ton of fuel			1.00E-06																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			1.00E-06																														
	ONOX	Tons/Ton of fuel			1.60E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Neenah CT1	NEN1 X CT																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.					[redacted]																												
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			150.00																														
	Operating	MW			150.00																														
	Emergency	MW			134.70																														
	Reserve	MW			134.70	134.70	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40	135.40
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0052																												
Emission Rates																																			
	SO2	Tons/Ton of fuel			2.70E-07																														
	NOX	Tons/Ton of fuel			1.80E-05																														
	CO2	Tons/Ton of fuel			5.94E-02																														
	CO	Tons/Ton of fuel			4.00E-08																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			7.50E-07																														
	ONOX	Tons/Ton of fuel			1.80E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Neenah CT2	NEN2 X CT																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.				[redacted]																													
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			150.00																														
	Operating	MW			150.00																														
	Emergency	MW			144.00																														
	Reserve	MW			144.00	144.00	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40	145.40
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.0097																												
Emission Rates																																			
	SO2	Tons/Ton of fuel			1.40E-07																														
	NOX	Tons/Ton of fuel			1.60E-05																														
	CO2	Tons/Ton of fuel			5.94E-02																														
	CO	Tons/Ton of fuel			4.00E-08																														
	Hg	lbs./ Ton of fuel			6.60E-06																														
	FPM	Tons/Ton of fuel			1.20E-06																														
	ONOX	Tons/Ton of fuel			1.60E-05																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

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Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

Riverside	RIV X																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.				[redacted]																													
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh			[redacted]																														
	Trajectory		No																																
Capacities																																			
	Rated	MW			610.00																														
	Operating	MW			610.00																														
	Emergency	MW			568.28																														
	Reserve	MW			568.28	568.28	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37	545.37
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	0.9597																												
Emission Rates																																			
	SO2	Tons/Ton of fuel			2.90E-07																														
	NOX	Tons/Ton of fuel			9.40E-06																														
	CO2	Tons/Ton of fuel			5.94E-02																														
	CO	Tons/Ton of fuel			6.80E-08																														
	Hg	lbs./ Ton of fuel			3.30E-09																														
	FPM	Tons/Ton of fuel			9.50E-07																														
	ONOX	Tons/Ton of fuel			9.40E-06																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Edgewater 3	EDG3 X R15																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory		No																																
Capacities																																			
	Rated	MW			71.00																														
	Operating	MW			0.00																														
	Emergency	MW			54.30																														
	Reserve	MW			54.30	54.30	68.60	68.60	0.00																										
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW			1.0000	1.0000	1.2633		0.00																										
Emission Rates																																			
	SO2	Tons/Ton of fuel			4.66E-03																														
	NOX	Tons/Ton of fuel			1.67E-03																														
	CO2	Tons/Ton of fuel			2.012																														
	CO	Tons/Ton of fuel			1.71E-03																														
	Hg	lbs./ Ton of fuel			7.90E-06																														
	FPM	Tons/Ton of fuel			4.58E-04																														
	ONOX	Tons/Ton of fuel			1.67E-03																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

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Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Edgewater 4	EDG4 X E4R18																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Net Book Value (NBV) - WPL Share		k$				[redacted]																													
On-Going Capital Costs (OGCC) - WPL Share		k$																																	
NBV Revenue Requirements - WPL Share		k$																																	
OGCC Revenue Requirements - WPL Share		k$																																	
NBV and OGCC Revenue Requirements - WPL Share		k$																																	
NBV and OGCC Revenue Requirements - Whole Unit		$/kW		Yes																															
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory		No																																
Capacities - WPL Share																																			
	Rated	MW			200.48																														
	Operating	MW			200.48	200.48	200.48	200.48	200.48	200.48	200.48	0.00																							
	Emergency	MW			210.46	210.46	210.46	210.46	210.46	210.46	210.46	0.00																							
	Reserve	MW			210.46	210.46	198.87	198.87	198.87	198.87	198.87	0.00																							
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW			1.0000							0.0000																							
	Emergency	MW			1.0000							0.0000																							
	Reserve	MW			1.0000	1.0000	0.9449					0.0000																							
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			5.05E-03																														
	NOX	Tons/Ton of fuel			1.32E-03	1.25E-03																													
	CO2	Tons/Ton of fuel			1.871																														
	CO	Tons/Ton of fuel			3.95E-04																														
	Hg	lbs./ Ton of fuel			2.30E-05	2.30E-05	2.30E-05	1.96E-05																											
	FPM	Tons/Ton of fuel			2.51E-04																														
	ONOX	Tons/Ton of fuel			1.32E-03																														
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX				1.0000	0.9500																													
	CO2		No																																
	CO2		No																																
	Hg				1.0000			0.8500																											
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Edgewater 5	EDG5 X E4R18																																		
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory																																		
Capacities																																			
	Rated	MW			395.00	395.00	395.00	395.00	385.00	385.00	385.00	385.00	385.00	403.97																					
	Operating	MW			395.00	395.00	395.00	395.00	385.00	385.00	385.00	385.00	385.00	403.97																					
	Emergency	MW			402.11	402.11	402.11	402.11	391.93	391.93	391.93	391.93	391.93	411.24																					
	Reserve	MW			402.11	402.11	406.41	406.41	406.49	406.49	406.49	406.49	406.49	405.77																					
Capacity Trajectories																																			
	Rated	MW			1.0000				0.9747					1.0227																					
	Operating	MW			1.0000				0.9747					1.0227																					
	Emergency	MW			1.0000				0.9747					1.0227																					
	Reserve	MW			1.0000	1.0000	1.0107		1.0109					1.0091																					
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			5.11E-03	5.11E-03	5.11E-03	5.11E-03	5.11E-03	6.13E-05																									
	NOX	Tons/Ton of fuel			1.19E-03	5.01E-04																													
	CO2	Tons/Ton of fuel			1.769																														
	CO	Tons/Ton of fuel			6.40E-04																														
	Hg	lbs./ Ton of fuel			2.40E-05	2.40E-05	2.40E-05	1.82E-05																											
	FPM	Tons/Ton of fuel			8.70E-05	8.70E-05	8.70E-05	1.13E-05																											
	ONOX	Tons/Ton of fuel			1.19E-03	5.01E-04																													
Emission Rate Trajectories (Multipliers)																																			
	SO2				1.0000					0.0120																									
	NOX				1.0000	0.4200																													
	CO2		No																																
	CO2		No																																
	Hg				1.0000			0.7600																											
	FPM				1.0000			0.1300																											
	ONOX				1.0000	0.4200																													
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Columbia Unit 1	COL1 X 3538																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory																																		
Capacities																																			
	Rated	MW			233.77	237.23	234.64	234.64	234.64	256.40	256.40																								
	Operating	MW			233.77	237.23	234.64	234.64	234.64	256.40	256.40																								
	Emergency	MW			255.72	259.51	256.67	256.67	256.67	280.48	280.48																								
	Reserve	MW			255.72	251.99	246.01	246.01	246.01	246.01	234.33																								
Capacity Trajectories																																			
	Rated	MW			1.0000	1.0148	1.0037			1.0968																									
	Operating	MW			1.0000	1.0148	1.0037			1.0968																									
	Emergency	MW			1.0000	1.0148	1.0037			1.0968																									
	Reserve	MW			1.0000	0.9854	0.9620				0.9164																								
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			5.34E-03	5.34E-03	6.41E-04																												
	NOX	Tons/Ton of fuel			1.25E-03	1.25E-03	1.25E-03	1.25E-03	1.25E-03	1.12E-03																									
	CO2	Tons/Ton of fuel			1.907																														
	CO	Tons/Ton of fuel			9.27E-04																														
	Hg	lbs./ Ton of fuel			1.30E-04	1.30E-04	1.95E-05																												
	FPM	Tons/Ton of fuel			4.79E-04	4.79E-04	1.15E-04																												
	ONOX	Tons/Ton of fuel			1.25E-03	1.25E-03	1.25E-03	1.25E-03	1.25E-03	1.12E-03																									
Emission Rate Trajectories (Multipliers)																																			
	SO2				1.0000		0.12																												
	NOX				1.0000					0.9																									
	CO2		No																																
	CO2		No																																
	Hg				1.0000		0.1500																												
	FPM				1.0000		0.24																												
	ONOX				1.0000					0.9																									
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Columbia Unit 2	COL2 X 3538																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory																																		
Capacities																																			
	Rated	MW			235.62	236.77	234.18	234.18	256.40	256.40	256.40	254.89																							
	Operating	MW			235.62	236.77	234.18	234.18	256.40	256.40	256.40	254.89																							
	Emergency	MW			248.41	249.63	246.89	246.89	270.32	270.32	270.32	268.73																							
	Reserve	MW			248.41	247.22	248.84	248.84	227.27	232.23	232.23	233.61																							
Capacity Trajectories																																			
	Rated	MW			1.0000	1.0049	0.9939		1.0882			1.0818																							
	Operating	MW			1.0000	1.0049	0.9939		1.0882			1.0818																							
	Emergency	MW			1.0000	1.0049	0.9939		1.0882			1.0818																							
	Reserve	MW			1.0000	0.9952	1.0017		0.9149	0.9349		0.9404																							
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			5.14E-03	5.14E-03	5.65E-04																												
	NOX	Tons/Ton of fuel			1.18E-03	1.18E-03	1.18E-03	1.18E-03	1.18E-03	1.06E-03																									
	CO2	Tons/Ton of fuel			1.824																														
	CO	Tons/Ton of fuel			1.14E-03																														
	Hg	lbs./ Ton of fuel			5.80E-05	5.80E-05	8.70E-06																												
	FPM	Tons/Ton of fuel			1.04E-04	1.04E-04	2.50E-05																												
	ONOX	Tons/Ton of fuel			1.18E-03	1.18E-03	1.18E-03	1.18E-03	1.18E-03	1.06E-03																									
Emission Rate Trajectories (Multipliers)																																			
	SO2				1.0000		0.1100																												
	NOX				1.0000					0.9000																									
	CO2		No																																
	CO2		No																																
	Hg				1.0000		0.1500																												
	FPM				1.0000		0.2400																												
	ONOX				1.0000					0.9000																									
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.3636	2.3636	2.3636	2.3636	2.3636																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Columbia 1 & 2 Revenue Requirement (R/R)	COL_RR 3538																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Col 1 Net Book Value R/R - WPL Share		k$				[redacted]																													
Col 1 On-Going Capital Costs R/R - WPL Share		k$																																	
Col 1 Turbine and Mill Costs R/R - WPL Share		k$																																	
Col 1 Scrubber & Bag House Costs R/R - WPL Share		k$																																	
Columbia 1 Revenue Requirements - - WPL Share		k$																																	
Col 2 Net Book Value R/R - - WPL Share		k$				[redacted]																													
Col 2 On-Going Capital Costs R/R - WPL Share		k$																																	
Col 2 Turbine and Mill Costs R/R - WPL Share		k$																																	
Col 2 Scrubber & Bag House Costs R/R - WPL Share		k$																																	
Col 2 SCR Costs R/R - WPL Share		k$																																	
Col 2 SCR Capital Maintenance Costs R/R - WPL Share		k$																																	
Columbia 2 Revenue Requirements - - WPL Share		k$																																	
Combined Units Revenue Requirements - - WPL Share		k$				[redacted]																													
Combined Units Revenue Requirements - Whole Unit at 1,000 kw		$/kW		Yes																															
Fixed Operations and Maintenance Costs		$/kW-yr.	No																																
Variable Operations and Maintenance Costs		$/MWH	No																																
Full Load Heat Rate		BTU/kWh	No			99999																													
	Trajectory		No																																
Capacities																																			
	Rated	MW				1,000.00																													
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW	No																																
Capacity Trajectories																																			
	Rated	MW	No																																
	Operating	MW	No																																
	Emergency	MW	No																																
	Reserve	MW	No																																
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel	No																																
	NOX	Tons/Ton of fuel	No																																
	CO2	Tons/Ton of fuel	No																																
	CO	Tons/Ton of fuel	No																																
	Hg	lbs./ Ton of fuel	No																																
	FPM	Tons/Ton of fuel	No																																
	ONOX	Tons/Ton of fuel	No																																
Emission Rate Trajectories (Multipliers)																																			
	SO2		No																																
	NOX		No																																
	CO2		No																																
	CO2		No																																
	Hg		No																																
	FPM		No																																
	ONOX		No																																
Emission Rate Segment Multiplier			No																																
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential																																			
Nelson Dewey 1	NED1 X R15																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory		No																																
Capacities																																			
	Rated	MW			102.00																														
	Operating	MW			102.00																														
	Emergency	MW			104.00																														
	Reserve	MW			104.00	100.40	100.40	100.40	0.00																										
Capacity Trajectories																																			
	Rated	MW	No		1.0000																														
	Operating	MW	No		1.0000																														
	Emergency	MW	No		1.0000																														
	Reserve	MW			1.0000	0.9654			0.0000																										
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			6.63E-03																														
	NOX	Tons/Ton of fuel			5.48E-03	2.36E-03																													
	CO2	Tons/Ton of fuel			2.38																														
	CO	Tons/Ton of fuel			7.28E-04																														
	Hg	lbs./ Ton of fuel			4.90E-05																														
	FPM	Tons/Ton of fuel			9.10E-05																														
	ONOX	Tons/Ton of fuel			5.48E-03	2.36E-03																													
Emission Rate Trajectories (Multipliers)																																			
	SO2				1.0000																														
	NOX				1.0000	0.4300																													
	CO2		No																																
	CO2		No																																
	Hg				1.0000																														
	FPM		No																																
	ONOX				1.0000	0.4300																													
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Table 5.1.3 WPL 2014 IRP Existing Unit Detailed Costs, Cost Escalation, Full-Load Heat Rate, Capacities, Emission Rate, and Emission Rate Multipliers - Confidential

Nelson Dewey 2	NED2 X R15																																		
		Units (All Costs are Year of Occurrence)	Item Specified in EGEAS for This Unit	Costs Appear in EGEAS Detailed Costs (EBPH)	Base Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
On-Going Capital Costs		$/kW	No																																
On-Going Capital Costs Revenue Requirements		$/kW	No																																
Fixed Operations and Maintenance Costs		$/kW-yr.			[redacted]																														
EGEAS-Type Escalator																																			
Variable Operations and Maintenance Costs		$/MWH																																	
EGEAS-Type Escalator																																			
Full Load Heat Rate		BTU/kWh																																	
	Trajectory		No																																
Capacities																																			
	Rated	MW			102.00																														
	Operating	MW			102.00																														
	Emergency	MW			103.00																														
	Reserve	MW			103.00	103.00	101.20	101.20	0.00																										
Capacity Trajectories																																			
	Rated	MW	No		1.0000																														
	Operating	MW	No		1.0000																														
	Emergency	MW	No		1.0000																														
	Reserve	MW			1.0000		0.9825																												
Emission Rates (Only rates that change are extended beyond the base year values)																																			
	SO2	Tons/Ton of fuel			6.64E-03																														
	NOX	Tons/Ton of fuel			5.79E-03	2.49E-03																													
	CO2	Tons/Ton of fuel			2.485																														
	CO	Tons/Ton of fuel			6.19E-04																														
	Hg	lbs./ Ton of fuel			5.30E-05																														
	FPM	Tons/Ton of fuel			6.20E-05																														
	ONOX	Tons/Ton of fuel			5.79E-03	2.49E-03																													
Emission Rate Trajectories (Multipliers)																																			
	SO2				1.0000																														
	NOX				1.0000	0.4300																													
	CO2		No																																
	CO2		No																																
	Hg				1.0000																														
	FPM		No																																
	ONOX				1.0000	0.4300																													
Emission Rate Segment Multiplier		[redacted]																																	
					Emission	/ Segment																													
						1	2	3	4	5	6	7	8	9	10	11	12																		
					ONOX					2.36364	2.36364	2.36364	2.36364	2.36364																					

Appendix 6A

WPL Resource Forecast

(*Confidential information is marked gray*)

Table 6.2.1 WPL 2014 IRP, Calendar Presentation of Expected Supply-Side Resource Zonal Resource Credits by CP Node

Confidential Information is High-Lighted in Gray.

Ref No.	Commercial Participant (CP) Node	Resource	Base Year (Raw Data)	Base Year (Adjusted for EGEAS)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	Total Ref. Nos. 1 - 36		2722.6	2781.9	2827.6	2797.6	2817.6	2555.2	2567.6	2577.7	2418.1	2246.6	2265.0	2265.0	2265.0	2251.9	2251.9	2251.9	2248.6	2248.6	2248.6	2248.6	2248.6	2248.6	2248.6	2248.6	2106.1	1849.1	1849.1	1849.1	1596.4	1596.4	1596.4	1596.4	1596.4
	Resources																																		
1	ALTE.CEDARDGE	Cedar Ridge	7.9	7.9	7.9	[redacted]																													
2	ALTE.COLUMBAL1	Columbia #1	255.7	255.7	255.7	246.9	246.9	246.9	246.9	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0								
3	ALTE.COLUMBAL2	Columbia #2	248.4	248.4	248.4	247.3	247.3	247.3	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7	252.7					
4	ALTE.EDEN0MONT	Monfort	0.4	0.4	0.4	[redacted]																													
5	ALTE.EDGG3G3	Edgewater 3	54.3	54.3	54.3	68.6	68.6																												
6	ALTE.EDGG4G4	Edgewater 4	210.5	210.5	210.5	198.9	198.9	198.9	198.9	198.9																									
7	ALTE.EDGG5G5	Edgewater 5	402.1	402.1	402.1	[redacted]																													
8	ALTE.KILBOUNIL	Kilbourn	6.2	6.2	6.2																														
9	ALTE.NEDG1G1	Nelson Dewey 1	104.0	104.0	104.0	100.4	100.4																												
10	ALTE.NEDG2G2	Nelson Dewey 2	103.0	103.0	103.0	101.2	101.2																												
11	ALTE.NEENAHG1	Neenah CT1	134.7	134.7	134.7	[redacted]																													
12	ALTE.NEENAHG2	Neenah CT2	144.0	144.0	144.0																														
13	ALTE.PDSG1S1	Prairie du Sac 1	14.1	14.1	14.1																														
14	ALTE.RORG3R3	Rock River 3	23.3	23.3	23.3																														
15	ALTE.RORG5R5	Rock River 5	47.9	47.9	47.9																														
16	ALTE.RORG6R6	Rock River 6	0.0	20.0	0.0																														
18	ALTE.SFONDDLG2	South Fond Du Lac 2	71.6	71.6	71.6																														
19	ALTE.SFONDDLG3	South Fond Du Lac 3	71.3	71.3	71.3																														
21	ALTE.SHEB1	Sheboygan Falls 1	140.3	140.3	140.3	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9	140.9
22	ALTE.SHEB2	Sheboygan Falls 2	141.7	141.7	141.7	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8	138.8
23	ALTE.SHEEPSIN1	Sheepskin 1	32.9	32.9	32.9	[redacted]																													
24	ALTE.TOWNECT_1	Riverside CT1	159.3	568.3	159.3																														
25	ALTE.TOWNECT_2	Riverside CT2	157.6		157.6																														
26	ALTE.TOWNEST11	Riverside STM 3	125.7		125.7																														
27	ALTE.TOWNEST12	Riverside STM 3	125.7		125.7																														
28	ALTE.TURTLE0R4	Rock River 4	13.6	13.6	13.6																														
29	WPS.ALTE_FORWD	Forward II	3.4	3.4	3.4																														
30	ALTW.WORT1	Top of Iowa 1 (Worth)	4.4	4.4	4.4																														
31	ALTW.CRLK2WPL	Cristal Lake 2	0.0	13.1	0.0																														
32	ALTW.BENT_TREE	Bent Tree	0.0	26.2	0.0																														
33	ZRC Transfers		0.0																																
34	Petenwell II	Petenwell Hydro ZRC	10.1	10.1	10.1																														
35	Castle Rock II	Castle Rock ZRC	8.8	8.8	8.8																														
36	WPS.JUNEAUG31	Juneau/Petenwell CT ZRC	4.7	4.7	4.7																														
	ZRC Transfers - Modeled in EGEAS ORTHOG as ZRC Transfer																																		
39	ALTE.TOWNEST12	Riverside STM 3	[redacted]																																
40	WPL - BELW 5 MW to replace 4.5 MW FRT	BLEW																																	
41	Power Purchase	[redacted]																																	

Public Version

Confidential information and information making such information determinable is high-lighted in gray

Table 6.2.2 WPL 2014 IRP Expected Supply-Side Resources in EGEAS Prior to Expansion Additions
Annual Changes in Resources Underlying Net Resource Changes from 2013 to 2020

Line No.			2013	2014	2015	2016	2017	2018	2019	2020
1		Adjusted Net Peak Demand	2,520.6	[redacted]						
2		Obligation	2,753.2							
3		Plus Supply-Side Resources (MW UCAP)	2,827.6							
4		Plus Demand-Side Resources	147.2							
5		Plus Supply-Side Purchase and Sales Contracts	(105.0)							
6		Less Net Resources	2,869.8							
7		WPL Position (+Long/-Short) = line 2 - line 6	116.6							
8		Reserves = line 6 / line 1 - 1	13.9%							
9										
10		Annual changes in resources underlying net resources from 2013 to 2020								
11		Supply-Side		[redacted]						
12		Demand-Side								
13		Supply-Side Purchase and Sales Contracts								
14		Net Resources								
15		Total Change in Net Resources from 2013 to end of 2019								
16										
17		Annual changes in resources underlying net resource changes from 2013 to 2020								
18	Year	Supply-Side Resources								
19	2014	Various unit capacity changes due to GVTC and XEFORd updates		[redacted]						
20	2015	Rock River Unit 6 capacity ramp up								
21	2016	Edgewater Unit 3 and Nelson Dewey Units 1 & 2 retirements								
22	2016	Edgewater 5 AQCS Derate								
23	2016	Rock River Unit 6 ramp up								
24	2017	Columbia Unit 2 trubine and mill upgrade								
25	2017	Rock River Unit 6 ramp up								
26	2017	Top of Iowa end of PPA 2016								
27	2018	Columbia Unit 1 trubine and mill upgrade								
28	2019	Edgewater Unit 4 retirement								
29	2019	Provisional capacity for wind units Crystal Lake								
30	2019	Bent Tree								
31	2020	Rock River Units 3, 4, 5, and 6 and Sheepskin Unit 1 Retirements at the end of 2019								
32										
33	Year	Demand-Side Resources								
34	2014	Reduction of Interruptible Capacity		[redacted]						
35	2015	Increase in Interruptible Capacity								
36	2016	Increase in Interruptible Capacity								
37	2017	Increase in Interruptible Capacity								
38	2018	Increase in Interruptible Capacity								
39	2019	Increase in Interruptible Capacity								
40	2020	Increase in Interruptible Capacity								
41										
42	Year	Supply-Side Purchase and Sales Contracts								
43	2014	Completion of third-party capacity obligation at Riverside		[redacted]						
44	2015	Transmission loss adjustment								
45	2016	Capacity Purchase from We Energies								
46	2017	Continued Capacity Purchase from We Energies								
47	2018	Capacity Purchase from We Energies terminated at the end of 2017								
48	2019									
49	2020									
50										
51	Year	Retirement High-Lights, WPL Owned Capacity Reductions								
52	2016	Retirements of Edgewater 3, Nelson Dewey 1 and 2 at the end of 2015:		[redacted]						
53	2019	Assumed Retirement of Edgewater Unit 4 at the end of 2018:								
54	2020	Assumed Retirement of Rock River 3, 4, 5, and 6, and Sheepskin 1 at the end of 2019:								
55		Total at the end of 2019								

Table 6.2.3 WPL 2014 IRP Expected Demand-Side Resources Classified as Supply-Side Resources in EGEAS.

Supply Side Value	Transmission Adjustment	Demand Side Value	Factor	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		Demand Resources, Interruptible Demand Resources, Direct Load Control			130.5	131.8	133.1	134.5	135.8	137.2	138.5	139.9	141.3	142.7	144.2	145.6	147.1	148.5	150.0	151.5	153.0	154.6	156.1	157.7	159.3	160.8	162.5	164.1	165.7	167.4	169.1	170.7	172.4	174.2
		Total Demand Resources		134.8	130.5	131.8	133.1	134.5	135.8	137.2	138.5	139.9	141.3	142.7	144.2	145.6	147.1	148.5	150.0	151.5	153.0	154.6	156.1	157.7	159.3	160.8	162.5	164.1	165.7	167.4	169.1	170.7	172.4	174.2
	Transmission Loss Adjustment (demand side to supply side)		2.85%	3.8	3.7	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.9	4.9	5.0
Planning Reserve Margin Adjustment			7.30%	8.6	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.3	11.4	11.5	11.6	11.7	11.8	12.0	12.1	12.2	12.3	12.4	12.6	12.7	12.8	12.9	13.1
Demand Side Resources (adj. to supply side)				147.2	144.0	145.5	146.9	148.4	149.9	151.4	152.8	154.4	155.9	157.5	159.1	160.7	162.3	163.9	165.5	167.2	168.8	170.6	172.3	174.0	175.8	177.5	179.3	181.1	182.9	184.7	186.6	188.4	190.3	192.2

Appendix 7A

Black & Veatch 2013 Power Characterization Study

(*Confidential in its entirety*)

Appendix 7B

New Resource Planning Alternative Data

(*Confidential information is marked gray*)

CONFIDENTIAL information is high-lighted in gray.

Table 7.3.2 Generic Resource Alternatives: Costs and Characteristics
WPL 2014 IRP
Costs are in 2013$
In the Order They Appear in EGEAS

EGEAS Unit Name	Description	Rated Capacity (MW)	Operating Capacity (MW)	Reserve Capacity (MW)	Forced Outage Rate	Full Load Heat Rate (BTU/KWH)	Fixed O&M Cost ($/KW-Yr.)	Technology Variable O&M ($/MWH)	PTC Variable O&M ($/MWh)	Total Variable O&M ($/MWH)	EPC Costs ($/KW)	Owner's & AFUDC Cost	Capital Cost ($/KW)	EPC cost of B&V unit ($M)	Owners Cost of B&V Unit ($M)	Total cost of B&V Unit ($M-2013)	Book Life (Years)
WIND P 100MW WI	35% Capacity Factor - WI	100.0	100.0	14.1	[redacted]												
WIND P 100MW IA	41% Capacity Factor - IA	100.0	100.0	0.0	[redacted]												
SOLR P 10MW	PV 20.1% Capacity Factor	10.0	10.0	6.2	[redacted]												
NCC1 P 300MW	1x1 GE 7F 5-Series CC	299.8	299.8	284.5	[redacted]												
NCC2 P 605MW	2x1 GE 7F 5-Series CC	604.7	604.7	573.8	[redacted]												
NCT2 P 192MW	GE 7F 5-Series CT	191.7	191.7	180.3	[redacted]												
BIOM P 35MW	Direct-Fired Open-Loop Biomass	35.0	35.0	32.9	[redacted]												
BIOG P 10MW	Landfill Gas	10.0	10.0	9.4	[redacted]												
APUR P 50MW 1YR	Capacity only	50.0	0.0	50.0	0.000%		varies										1

CT means combustion turbine, CC means combined cycle, PV means photovoltaic.
In EGEAS, 10 year Production Tax Credit (PTC) impact is modeled using Detailed Variable Costs for Biomass, Biogas, and Wind:
  Biomass (open loop) and Biogas: 10-yr PTC beginning at $11/MWH in 2013, grossed up by 40.137% tax rate and levelized over 30yr life, results in levelized PTC of $13.16.
  Wind: 10-yr PTC beginning at $23/MWH in 2013, grossed up by 40.137% tax rate and levelized over 30yr life, results in levelized PTC of $27.40.
  Levelized PTC work paper in file, "WPL 2014 IRP - PTC cost and Levelized Variable Benefit per MWh Work Paper (draft 2014-07-17).xlsx".
In EGEAS, Solar 25 year Investment Tax Credit impact is modeled using Detailed Capital Costs:
  30% of capital investment spread over 25 years, 30% x $3,080/kw / (1 - 40.137% tax gross-up) / 25 yrs. = -62 $/kw-y over 25 year book life and 100% Levelized Fixed Charge Rate.
  Drops from 30% to 10% for investments after 2016.
Escalators for fixed O&M are 3 percent per year starting in 2013 through the planning and extension periods. For variable O&M escalations are 2.3 %, 2.8 %, and 2 % for 2013, 2014, and 2015 through the planning and extension periods, respectively.

Appendix 7C

New Unit Capital Cost Estimates

(*Confidential information is marked gray*)

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Table 7.3.3 WPL 2014 IRP Capital Escalation Rates, Reflecting WPL's Modification of Excluding EIA's Technological Optimism and Project Contingency for the Following Technologies

Confidential data is high-lighted in gray.

Nominal Escalation Rate (to next year, i.e. EGEAS Type) = (1 + Real %) * (1 + Inflation %) - 1

Wood Mackenzie Inflation*

Potential Online Year	38 Combustion Turbine (CT)	39 Advanced CT	42 Advanced Combined Cycle	47 Biomass	49 Landfill Gas	53 Wind	56 Solar Photo Voltaic		YEAR	H2 2013 US CPI During specified year
2011									2011	[redacted]
2012									2012	
2013	3.1%	3.0%	3.0%	-1.6%	3.1%	3.0%	-5.2%		2013	
2014	4.8%	4.6%	4.8%	1.0%	4.8%	4.8%	0.6%		2014	
2015	3.0%	2.3%	2.5%	2.8%	3.0%	3.0%	-0.8%		2015	
2016	2.0%	0.7%	1.2%	1.9%	2.0%	2.0%	0.3%		2016	
2017	1.6%	0.8%	1.1%	1.5%	1.6%	1.6%	1.3%		2017	
2018	1.4%	0.6%	0.9%	1.3%	1.4%	1.4%	1.1%		2018	
2019	1.3%	0.5%	0.8%	1.1%	1.3%	1.3%	1.0%		2019	
2020	1.0%	0.5%	0.7%	0.9%	1.0%	1.0%	0.7%		2020	
2021	1.0%	0.3%	0.6%	0.9%	1.0%	1.0%	0.7%		2021	
2022	1.1%	0.8%	0.9%	0.9%	1.1%	1.1%	0.8%		2022	
2023	1.2%	0.5%	0.8%	1.1%	1.2%	1.2%	0.9%		2023	
2024	1.2%	0.1%	0.5%	1.0%	1.2%	1.2%	0.8%		2024	
2025	1.3%	0.5%	0.8%	1.1%	1.3%	1.3%	0.9%		2025	
2026	1.2%	0.6%	0.9%	1.0%	1.2%	1.2%	0.9%		2026	
2027	1.2%	0.6%	0.8%	1.0%	1.2%	1.2%	0.9%		2027	
2028	1.2%	0.2%	0.6%	1.0%	1.2%	1.2%	0.8%		2028	
2029	1.2%	0.7%	0.9%	1.0%	1.2%	1.2%	0.8%		2029	
2030	1.2%	0.7%	0.9%	1.0%	1.2%	1.2%	0.8%		2030	
2031	1.1%	0.7%	0.9%	1.0%	1.1%	1.1%	0.8%		2031	
2032	1.1%	0.8%	0.9%	0.9%	1.1%	1.1%	0.7%		2032	
2033	1.1%	0.8%	0.9%	0.9%	1.1%	1.1%	0.7%		2033	
2034	1.0%	0.8%	0.9%	0.9%	1.0%	1.0%	0.7%		2034	
2035	1.0%	0.7%	0.9%	0.9%	1.0%	1.0%	0.5%		2035	
2036	1.1%	0.8%	1.0%	1.0%	1.1%	1.1%	0.4%		*2036*	
2037	1.2%	1.2%	1.2%	1.0%	1.2%	1.2%	1.1%		*2037*	
2038	1.1%	1.2%	1.2%	1.0%	1.1%	1.1%	1.1%		*2038*	
2039	1.1%	1.2%	1.2%	1.0%	1.1%	1.1%	1.1%		*2039*	
2040	1.1%	1.2%	1.2%	1.0%	1.1%	1.1%	1.1%		*2040*	
2041	1.1%	1.2%	1.2%	1.0%	1.1%	1.1%	1.1%		*2041*	
2042	1.1%	1.2%	1.2%	1.0%	1.1%	1.1%	1.1%		*2042*	

[redacted]

Appendix 7D

Production Tax Credit Calculations

(*Does not contain confidential information*)

Table 7.3.4 WPL 2014 IRP Summary of the Development of Levelized Production Tax Credit for New Wind Units.

Levelized PTC price per MWH for a 30 year operating life

100	MW
	Installed Capital cost/kW ($2013)
	$M installed costs
	Levelized Carrying Charge Rate
	$M Annual carrying Costs
	Annual ongoing fixed O&M $/kw-yr ($2013)
	fixed O&M inflation
100.0%	PTC is independent of Capacity Factor - 100% used for calculation purposes only
876.0	Long Term Annual GWH
7.82%	Discount Rate for LCOE calcs
40.137%	Effective Tax Rate for PTC gross-up

life	Year	10 yr PTC $/MWH before gross-up	10 yr PTC $/MWH after gross-up	GWH	PTC $M	ongoing O&M $M	Carrying Costs $M	total cost $M	annual $/MWH	levelized $/MWH	levelized $M
1	2019	$ 26.00	$ 43.43	876	$ (38.05)	$ -	$ -	$ (38.05)	$ (43.43)	**$ (27.40)**	$ (24.00)
2	2020	$ 26.00	$ 43.43	876	$ (38.05)	$ -	$ -	$ (38.05)	$ (43.43)	**$ (27.40)**	$ (24.00)
3	2021	$ 27.00	$ 45.10	876	$ (39.51)	$ -	$ -	$ (39.51)	$ (45.10)	**$ (27.40)**	$ (24.00)
4	2022	$ 27.00	$ 45.10	876	$ (39.51)	$ -	$ -	$ (39.51)	$ (45.10)	**$ (27.40)**	$ (24.00)
5	2023	$ 28.00	$ 46.77	876	$ (40.97)	$ -	$ -	$ (40.97)	$ (46.77)	**$ (27.40)**	$ (24.00)
6	2024	$ 28.00	$ 46.77	876	$ (40.97)	$ -	$ -	$ (40.97)	$ (46.77)	**$ (27.40)**	$ (24.00)
7	2025	$ 29.00	$ 48.44	876	$ (42.44)	$ -	$ -	$ (42.44)	$ (48.44)	**$ (27.40)**	$ (24.00)
8	2026	$ 29.00	$ 48.44	876	$ (42.44)	$ -	$ -	$ (42.44)	$ (48.44)	**$ (27.40)**	$ (24.00)
9	2027	$ 30.00	$ 50.11	876	$ (43.90)	$ -	$ -	$ (43.90)	$ (50.11)	**$ (27.40)**	$ (24.00)
10	2028	$ 31.00	$ 51.78	876	$ (45.36)	$ -	$ -	$ (45.36)	$ (51.78)	**$ (27.40)**	$ (24.00)
11	2029			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
12	2030			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
13	2031			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
14	2032			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
15	2033			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
16	2034			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
17	2035			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
18	2036			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
19	2037			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
20	2038			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
21	2039			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
22	2040			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
23	2041			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
24	2042			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
25	2043			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
26	2044			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
27	2045			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
28	2046			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
29	2047			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
30	2048			876		$ -	$ -	$ -	$ -	**$ (27.40)**	$ (24.00)
							PVRR $M:	($274.95)		PVRR $M:	($274.95)

Use goal seek to find the value of the levelized total cost PTC so that the difference between the PVRR of the annual and levelized PTC/MWH is $0: $0.00

Assumptions & sources used in this analysis:

> Levelized Carrying Charge per New wind LCCR tab.

> Long term GWH (future GWH projections) per capacity factor profile for Cedar Ridge * 8.6% multipler (per Bruce Kinner e-mail 07/10/2014) for turbine technology improvement to Siemens SWT-2.3-101 (~32.6% CF wind farm).

> Discount rate and Effective Tax Rate per New wind LCRR tab.

> PTC $/MWH values per PTC tab.

Table 7.3.5 WPL 2014 IRP Summary of the Development of Levelized Production Tax Credit for New Biomass and Biogas Units.

Levelized PTC price per MWH for a 30 year operating life

35	MW
	Installed Capital cost/kW ($2013)
	$M installed costs
	Levelized Carrying Charge Rate
	$M Annual carrying Costs
	Annual ongoing fixed O&M $/kw-yr. ($2013)
	fixed O&M inflation
100.0%	PTC is independent of Capacity Factor - 100% used for calculation purposes only
306.6	Long Term Annual GWH
7.82%	Discount Rate for LCOE calculations
40.137%	Effective Tax Rate for PTC gross-up

life	Year	10 yr. PTC $/MWH before gross-up	10 yr. PTC $/MWH after gross-up	GWH	PTC $M	ongoing O&M $M	Carrying Costs $M	total cost $M	annual $/MWH		levelized $/MWH	levelized $M
1	2019	$ 12.00	$ 20.05	306.6	$ (6.15)	$ -	$ -	$ (6.15)	$ (20.05)		**$ (13.16)**	$ (4.04)
2	2020	$ 13.00	$ 21.72	306.6	$ (6.66)	$ -	$ -	$ (6.66)	$ (21.72)		**$ (13.16)**	$ (4.04)
3	2021	$ 13.00	$ 21.72	306.6	$ (6.66)	$ -	$ -	$ (6.66)	$ (21.72)		**$ (13.16)**	$ (4.04)
4	2022	$ 13.00	$ 21.72	306.6	$ (6.66)	$ -	$ -	$ (6.66)	$ (21.72)		**$ (13.16)**	$ (4.04)
5	2023	$ 13.00	$ 21.72	306.6	$ (6.66)	$ -	$ -	$ (6.66)	$ (21.72)		**$ (13.16)**	$ (4.04)
6	2024	$ 14.00	$ 23.39	306.6	$ (7.17)	$ -	$ -	$ (7.17)	$ (23.39)		**$ (13.16)**	$ (4.04)
7	2025	$ 14.00	$ 23.39	306.6	$ (7.17)	$ -	$ -	$ (7.17)	$ (23.39)		**$ (13.16)**	$ (4.04)
8	2026	$ 14.00	$ 23.39	306.6	$ (7.17)	$ -	$ -	$ (7.17)	$ (23.39)		**$ (13.16)**	$ (4.04)
9	2027	$ 14.00	$ 23.39	306.6	$ (7.17)	$ -	$ -	$ (7.17)	$ (23.39)		**$ (13.16)**	$ (4.04)
10	2028	$ 15.00	$ 25.06	306.6	$ (7.68)	$ -	$ -	$ (7.68)	$ (25.06)		**$ (13.16)**	$ (4.04)
11	2029			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
12	2030			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
13	2031			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
14	2032			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
15	2033			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
16	2034			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
17	2035			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
18	2036			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
19	2037			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
20	2038			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
21	2039			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
22	2040			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
23	2041			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
24	2042			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
25	2043			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
26	2044			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
27	2045			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
28	2046			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
29	2047			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
30	2048			306.6		$ -	$ -	$ -	$ -		**$ (13.16)**	$ (4.04)
							PVRR $M:	($46.22)			PVRR $M:	($46.22)

Use goal seek to find the value of the levelized total cost PTC so that the difference between the PVRR of the annual and levelized PTC/MWH is $0: $0.00

Assumptions & sources used in this analysis:

> Levelized Carrying Charge per New wind LCCR tab.
> Long term GWH (future GWH projections) per capacity factor profile for Cedar Ridge * 8.6% multiplier (per Bruce Kinner e-mail 07/10/2014) for turbine technology improvement to Siemens SWT-2.3-101 (~32.6% CF wind farm).
> Discount rate and Effective Tax Rate per New wind LCRR tab.
> PTC $/MWH values per PTC tab.
> 30 year depreciable life per Brian Madonia in B&FP (depreciation studies)

Appendix 8A

EGEAS Reserve Annual Report

(*Confidential information is marked gray*)

Table 8.3.2.1 WPL 2014 IRP Load and Capability Position with Peak and Energy Base Forecast

Load and Capability Position With Peak and & Energy Base Forecast (November 2013)

Confidential

Confidential information and information making such information determinable is high-lighted in gray

	Non-Coincident Peak Load	Peak Adjustment Non-Coincident to Coincident	Transmission Loss Adjustment	Wholesale Contracts	Adjusted Net Coincident Peak Demand	EGEAS PRM (includes trans losses 2.85% and MISO PRM 7.3%)	**Obligation**	Supply Side Resources	**Demand Side Resources**	Total Resources	Resource Capacity Purchases and Sales	**Adjusted Net Resources**	WPL Position (Long/short)
Location in EGEAS Reserve Annual Report	**Peak Load**	Demand Side Mgmt.		Purch/Sale Contracts	Net Loads					Capacity	Purch/Sale	**Net Resources**	Obligation Less Net Resources
Formula	**Forecast**	[redacted]	less	add	=	add	=		**add**	=	add	=	
		[redacted]	2.870%			10.358%							
2013	2512.0	[redacted]	70.3	[redacted]	2520.6	232.6	**2753.2**	2827.6	[redacted]	[redacted]	[redacted]	**2869.8**	**117**
2014	**2547.8**	[redacted]	70.2	[redacted]	2540.9	263.2	**2804.1**	2797.6	[redacted]	[redacted]	[redacted]	**2936.6**	**133**
2015	**2585.4**	[redacted]	71.2	[redacted]	2566.0	265.8	**2831.8**	2817.6	[redacted]	[redacted]	[redacted]	**2958.6**	**127**
2016	**2618.9**	[redacted]	72.1	[redacted]	2587.5	268.0	**2855.5**	2555.2	[redacted]	[redacted]	[redacted]	**2852.6**	**(3)**
2017	**2634.3**	[redacted]	72.6	[redacted]	2480.6	256.9	**2737.5**	2567.6	[redacted]	[redacted]	[redacted]	**2866.5**	**129**
2018	**2654.1**	[redacted]	73.1	[redacted]	2499.1	258.9	**2758.0**	2577.7	[redacted]	[redacted]	[redacted]	**2727.6**	**(30)**
2019	**2672.1**	[redacted]	73.6	[redacted]	2515.9	260.6	**2776.5**	2418.1	[redacted]	[redacted]	[redacted]	**2569.5**	**(207)**
2020	**2691.9**	[redacted]	74.1	[redacted]	2534.4	262.5	**2796.9**	2246.6	[redacted]	[redacted]	[redacted]	**2399.4**	**(398)**
2021	**2711.9**	[redacted]	74.7	[redacted]	2553.0	264.4	**2817.4**	2265.0	[redacted]	[redacted]	[redacted]	**2419.4**	**(398)**
2022	**2732.1**	[redacted]	75.3	[redacted]	2571.8	266.4	**2838.2**	2265.0	[redacted]	[redacted]	[redacted]	**2420.9**	**(417)**
2023	**2752.2**	[redacted]	75.8	[redacted]	2590.6	268.3	**2858.9**	2265.0	[redacted]	[redacted]	[redacted]	**2422.5**	**(436)**
2024	**2772.5**	[redacted]	76.4	[redacted]	2609.4	270.3	**2879.7**	2251.9	[redacted]	[redacted]	[redacted]	**2411.0**	**(469)**
2025	**2792.9**	[redacted]	76.9	[redacted]	2628.5	272.3	**2900.8**	2251.9	[redacted]	[redacted]	[redacted]	**2412.6**	**(488)**
2026	**2813.5**	[redacted]	77.5	[redacted]	2647.7	274.2	**2921.9**	2251.9	[redacted]	[redacted]	[redacted]	**2414.2**	**(508)**
2027	**2834.2**	[redacted]	78.1	[redacted]	2666.9	276.2	**2943.1**	2248.6	[redacted]	[redacted]	[redacted]	**2412.5**	**(531)**
2028	**2855.1**	[redacted]	78.6	[redacted]	2686.5	278.3	**2964.8**	2248.6	[redacted]	[redacted]	[redacted]	**2414.1**	**(551)**
2029	**2876.1**	[redacted]	79.2	[redacted]	2706.1	280.3	**2986.4**	2248.6	[redacted]	[redacted]	[redacted]	**2415.8**	**(571)**
2030	**2897.3**	[redacted]	79.8	[redacted]	2725.8	282.3	**3008.1**	2248.6	[redacted]	[redacted]	[redacted]	**2417.4**	**(591)**
2031	**2918.7**	[redacted]	80.4	[redacted]	2745.7	284.4	**3030.1**	2248.6	[redacted]	[redacted]	[redacted]	**2419.2**	**(611)**
2032	**2940.2**	[redacted]	81.0	[redacted]	2765.8	286.5	**3052.3**	2248.6	[redacted]	[redacted]	[redacted]	**2420.9**	**(631)**
2033	**2961.8**	[redacted]	81.6	[redacted]	2785.9	288.6	**3074.5**	2248.6	[redacted]	[redacted]	[redacted]	**2422.6**	**(652)**
2034	**2983.7**	[redacted]	82.2	[redacted]	2806.3	290.7	**3097.0**	2248.6	[redacted]	[redacted]	[redacted]	**2424.4**	**(673)**
2035	**3005.6**	[redacted]	82.8	[redacted]	2826.7	292.8	**3119.5**	2106.1	[redacted]	[redacted]	[redacted]	**2283.6**	**(836)**
2036	**3027.8**	[redacted]	83.4	[redacted]	2847.5	294.9	**3142.4**	1849.1	[redacted]	[redacted]	[redacted]	**2028.4**	**(1,114)**
2037	**3050.1**	[redacted]	84.0	[redacted]	2868.3	297.1	**3165.4**	1849.1	[redacted]	[redacted]	[redacted]	**2030.2**	**(1,135)**
2038	**3072.5**	[redacted]	84.6	[redacted]	2889.2	299.3	**3188.5**	1849.1	[redacted]	[redacted]	[redacted]	**2032.0**	**(1,157)**
2039	**3095.2**	[redacted]	85.3	[redacted]	2910.2	301.4	**3211.6**	1596.4	[redacted]	[redacted]	[redacted]	**1781.1**	**(1,430)**
2040	**3118.0**	[redacted]	85.9	[redacted]	2931.5	303.6	**3235.1**	1596.4	[redacted]	[redacted]	[redacted]	**1783.0**	**(1,452)**
2041	**3140.9**	[redacted]	86.5	[redacted]	2952.9	305.9	**3258.8**	1596.4	[redacted]	[redacted]	[redacted]	**1784.8**	**(1,474)**
2042	**3164.1**	[redacted]	87.2	[redacted]	2974.5	308.1	**3282.6**	1596.4	[redacted]	[redacted]	[redacted]	**1786.7**	**(1,496)**

Table 8.3.2.2 WPL 2014 IRP Load and Capability Position with Peak and Energy High Forecast

Load and Capability Position With Peak and & Energy High Forecast (November 2013)

Confidential

Confidential information and information making such information determinable is high-lighted in gray

	Non-Coincident Peak Load	Peak Adjustment Non-Coincident to Coincident	Transmission Loss Adjustment	Wholesale Contracts	Adjusted Net Coincident Peak Demand	EGEAS PRM (includes trans losses 2.85% and MISO PRM 7.3%)	**Obligation**	Supply Side Resources	**Demand Side Resources**	Total Resources	Resource Capacity Purchases and Sales	**Adjusted Net Resources**	WPL Position (Long/short)
Location in EGEAS Reserve Annual Report	**Peak Load**	Demand Side Mgmt.		Purch/Sale Contracts	Net Loads					Capacity	Purch/Sale	**Net Resources**	Obligation Less Net Resources
Formula	**Forecast**	[redacted]	less	[redacted]	=	add	=		**add**	=	add	=	
		[redacted]	2.870%	[redacted]		10.358%							
2013	2512.0	[redacted]	70.3	[redacted]	2520.6	232.6	**2753.2**	2827.6	[redacted]	[redacted]	[redacted]	**2869.8**	**117**
2014	**2547.8**	[redacted]	70.2	[redacted]	2540.9	263.2	**2804.1**	2797.6	[redacted]	[redacted]	[redacted]	**2936.6**	**133**
2015	**2598.9**	[redacted]	71.6	[redacted]	2578.5	267.1	**2845.6**	2817.6	[redacted]	[redacted]	[redacted]	**2958.6**	**113**
2016	**2646.1**	[redacted]	72.9	[redacted]	2612.8	270.6	**2883.4**	2555.2	[redacted]	[redacted]	[redacted]	**2852.6**	**(31)**
2017	**2674.5**	[redacted]	73.7	[redacted]	2518.1	260.8	**2778.9**	2567.6	[redacted]	[redacted]	[redacted]	**2866.5**	**88**
2018	**2708.1**	[redacted]	74.6	[redacted]	2549.4	264.1	**2813.5**	2577.7	[redacted]	[redacted]	[redacted]	**2727.6**	**(86)**
2019	**2740.1**	[redacted]	75.5	[redacted]	2579.2	267.2	**2846.4**	2418.1	[redacted]	[redacted]	[redacted]	**2569.5**	**(277)**
2020	**2774.3**	[redacted]	76.4	[redacted]	2611.2	270.5	**2881.7**	2246.6	[redacted]	[redacted]	[redacted]	**2399.4**	**(482)**
2021	**2808.9**	[redacted]	77.4	[redacted]	2643.4	273.8	**2917.2**	2265.0	[redacted]	[redacted]	[redacted]	**2419.4**	**(498)**
2022	**2843.9**	[redacted]	78.3	[redacted]	2676.1	277.2	**2953.3**	2265.0	[redacted]	[redacted]	[redacted]	**2420.9**	**(532)**
2023	**2879.2**	[redacted]	79.3	[redacted]	2708.9	280.6	**2989.5**	2265.0	[redacted]	[redacted]	[redacted]	**2422.5**	**(567)**
2024	**2915.0**	[redacted]	80.3	[redacted]	2742.3	284.0	**3026.3**	2251.9	[redacted]	[redacted]	[redacted]	**2411.0**	**(615)**
2025	**2951.1**	[redacted]	81.3	[redacted]	2775.9	287.5	**3063.4**	2251.9	[redacted]	[redacted]	[redacted]	**2412.6**	**(651)**
2026	**2987.8**	[redacted]	82.3	[redacted]	2810.2	291.1	**3101.3**	2251.9	[redacted]	[redacted]	[redacted]	**2414.2**	**(687)**
2027	**3024.8**	[redacted]	83.3	[redacted]	2844.7	294.7	**3139.4**	2248.6	[redacted]	[redacted]	[redacted]	**2412.5**	**(727)**
2028	**3062.4**	[redacted]	84.3	[redacted]	2879.8	298.3	**3178.1**	2248.6	[redacted]	[redacted]	[redacted]	**2414.1**	**(764)**
2029	**3100.3**	[redacted]	85.4	[redacted]	2915.0	301.9	**3216.9**	2248.6	[redacted]	[redacted]	[redacted]	**2415.8**	**(801)**
2030	**3138.8**	[redacted]	86.5	[redacted]	2950.9	305.7	**3256.6**	2248.6	[redacted]	[redacted]	[redacted]	**2417.4**	**(839)**
2031	**3177.7**	[redacted]	87.5	[redacted]	2987.2	309.4	**3296.6**	2248.6	[redacted]	[redacted]	[redacted]	**2419.2**	**(877)**
2032	**3217.1**	[redacted]	88.6	[redacted]	3023.9	313.2	**3337.1**	2248.6	[redacted]	[redacted]	[redacted]	**2420.9**	**(916)**
2033	**3257.0**	[redacted]	89.7	[redacted]	3061.1	317.1	**3378.2**	2248.6	[redacted]	[redacted]	[redacted]	**2422.6**	**(956)**
2034	**3297.4**	[redacted]	90.8	[redacted]	3098.8	321.0	**3419.8**	2248.6	[redacted]	[redacted]	[redacted]	**2424.4**	**(995)**
2035	**3338.3**	[redacted]	92.0	[redacted]	3136.8	324.9	**3461.7**	2106.1	[redacted]	[redacted]	[redacted]	**2283.6**	**(1,178)**
2036	**3379.7**	[redacted]	93.1	[redacted]	3175.5	328.9	**3504.4**	1849.1	[redacted]	[redacted]	[redacted]	**2028.4**	**(1,476)**
2037	**3421.6**	[redacted]	94.2	[redacted]	3214.6	333.0	**3547.6**	1849.1	[redacted]	[redacted]	[redacted]	**2030.2**	**(1,517)**
2038	**3464.0**	[redacted]	95.4	[redacted]	3254.1	337.1	**3591.2**	1849.1	[redacted]	[redacted]	[redacted]	**2032.0**	**(1,559)**
2039	**3506.9**	[redacted]	96.6	[redacted]	3294.1	341.2	**3635.3**	1596.4	[redacted]	[redacted]	[redacted]	**1781.1**	**(1,854)**
2040	**3550.4**	[redacted]	97.8	[redacted]	3334.6	345.4	**3680.0**	1596.4	[redacted]	[redacted]	[redacted]	**1783.0**	**(1,897)**
2041	**3594.4**	[redacted]	99.0	[redacted]	3375.6	349.6	**3725.2**	1596.4	[redacted]	[redacted]	[redacted]	**1784.8**	**(1,940)**
2042	**3638.9**	[redacted]	100.2	[redacted]	3417.1	353.9	**3771.0**	1596.4	[redacted]	[redacted]	[redacted]	**1786.7**	**(1,984)**

Table 8.3.2.3 WPL 2014 IRP Load and Capability Position with Peak and Energy Low Forecast

Load and Capability Position With Peak and & Energy Low Forecast (November 2013)

Confidential

Confidential information and information making such information determinable is high-lighted in gray

	Non-Coincident Peak Load	Peak Adjustment Non-Coincident to Coincident	Transmission Loss Adjustment	Wholesale Contracts	Adjusted Net Coincident Peak Demand	EGEAS PRM (includes trans losses 2.85% and MISO PRM 7.3%)	**Obligation**	Supply Side Resources	**Demand Side Resources**	Total Resources	Resource Capacity Purchases and Sales	**Adjusted Net Resources**	WPL Position (Long/short)
Location in EGEAS Reserve Annual Report	**Peak Load**	Demand Side Mgmt.		Purch/Sale Contracts	Net Loads					Capacity	Purch/Sale	**Net Resources**	Obligation Less Net Resources
Formula	**Forecast**	[redacted]	less	[redacted]	=	add	=		**add**	=	add	=	
			2.870%			10.358%							
2013	2512.0		70.3		2520.6	232.6	**2753.2**	2827.6	[redacted]			**2869.8**	**117**
2014	**2547.8**		70.2		2540.9	263.2	**2804.1**	2797.6				**2936.6**	**133**
2015	**2572.0**		70.8		2553.5	264.5	**2818.0**	2817.6				**2958.6**	**141**
2016	**2591.8**		71.4		2562.2	265.4	**2827.6**	2555.2				**2852.6**	**25**
2017	**2594.4**		71.5		2443.4	253.1	**2696.5**	2567.6				**2866.5**	**170**
2018	**2600.8**		71.6		2449.4	253.7	**2703.1**	2577.7				**2727.6**	**24**
2019	**2605.3**		71.8		2453.6	254.1	**2707.7**	2418.1				**2569.5**	**(138)**
2020	**2611.5**		71.9		2459.4	254.7	**2714.1**	2246.6				**2399.4**	**(315)**
2021	**2617.8**		72.1		2465.3	255.4	**2720.7**	2265.0				**2419.4**	**(301)**
2022	**2624.0**		72.3		2471.0	255.9	**2726.9**	2265.0				**2420.9**	**(306)**
2023	**2630.1**		72.4		2476.8	256.5	**2733.3**	2265.0				**2422.5**	**(311)**
2024	**2636.2**		72.6		2482.4	257.1	**2739.5**	2251.9				**2411.0**	**(329)**
2025	**2642.4**		72.8		2488.2	257.7	**2745.9**	2251.9				**2412.6**	**(333)**
2026	**2648.5**		73.0		2493.8	258.3	**2752.1**	2251.9				**2414.2**	**(338)**
2027	**2654.7**		73.1		2499.7	258.9	**2758.6**	2248.6				**2412.5**	**(346)**
2028	**2660.8**		73.3		2505.3	259.5	**2764.8**	2248.6				**2414.1**	**(351)**
2029	**2667.0**		73.5		2511.1	260.1	**2771.2**	2248.6				**2415.8**	**(355)**
2030	**2673.2**		73.6		2516.9	260.7	**2777.6**	2248.6				**2417.4**	**(360)**
2031	**2679.4**		73.8		2522.7	261.3	**2784.0**	2248.6				**2419.2**	**(365)**
2032	**2685.7**		74.0		2528.5	261.9	**2790.4**	2248.6				**2420.9**	**(369)**
2033	**2691.9**		74.1		2534.4	262.5	**2796.9**	2248.6				**2422.6**	**(374)**
2034	**2698.2**		74.3		2540.2	263.1	**2803.3**	2248.6				**2424.4**	**(379)**
2035	**2704.5**		74.5		2546.1	263.7	**2809.8**	2106.1				**2283.6**	**(526)**
2036	**2710.8**		74.7		2551.9	264.3	**2816.2**	1849.1				**2028.4**	**(788)**
2037	**2717.1**		74.8		2557.9	264.9	**2822.8**	1849.1				**2030.2**	**(793)**
2038	**2723.4**		75.0		2563.7	265.5	**2829.2**	1849.1				**2032.0**	**(797)**
2039	**2729.7**		75.2		2569.6	266.2	**2835.8**	1596.4				**1781.1**	**(1,055)**
2040	**2736.1**		75.4		2575.5	266.8	**2842.3**	1596.4				**1783.0**	**(1,059)**
2041	**2742.4**		75.5		2581.4	267.4	**2848.8**	1596.4				**1784.8**	**(1,064)**
2042	**2748.8**		75.7		2587.4	268.0	**2855.4**	1596.4				**1786.7**	**(1,069)**

Table 8.3.2.4 WPL 2014 IRP Obligated Peak Load and Sensitivities

	WPL Obligated Peak Load (MW), 2013 P&E		
Year	Base Case	High Sensitivity	Low Sensitivity
2014	2,804	2,804	2,804
2015	2,832	2,846	2,818
2016	2,856	2,883	2,828
2017	2,737	2,779	2,697
2018	2,758	2,814	2,703
2019	2,776	2,846	2,708
2020	2,797	2,882	2,714
2021	2,817	2,917	2,721
2022	2,838	2,953	2,727
2023	2,859	2,990	2,733
2024	2,880	3,026	2,740
2025	2,901	3,063	2,746
2026	2,922	3,101	2,752
2027	2,943	3,139	2,759
2028	2,965	3,178	2,765
2029	2,986	3,217	2,771
2030	3,008	3,257	2,778
2031	3,030	3,297	2,784
2032	3,052	3,337	2,790
2033	3,075	3,378	2,797
2034	3,097	3,420	2,803
2035	3,120	3,462	2,810
2036	3,142	3,504	2,816
2037	3,165	3,548	2,823
2038	3,189	3,591	2,829
2039	3,212	3,635	2,836
2040	3,235	3,680	2,842
2041	3,259	3,725	2,849
2042	3,283	3,771	2,855

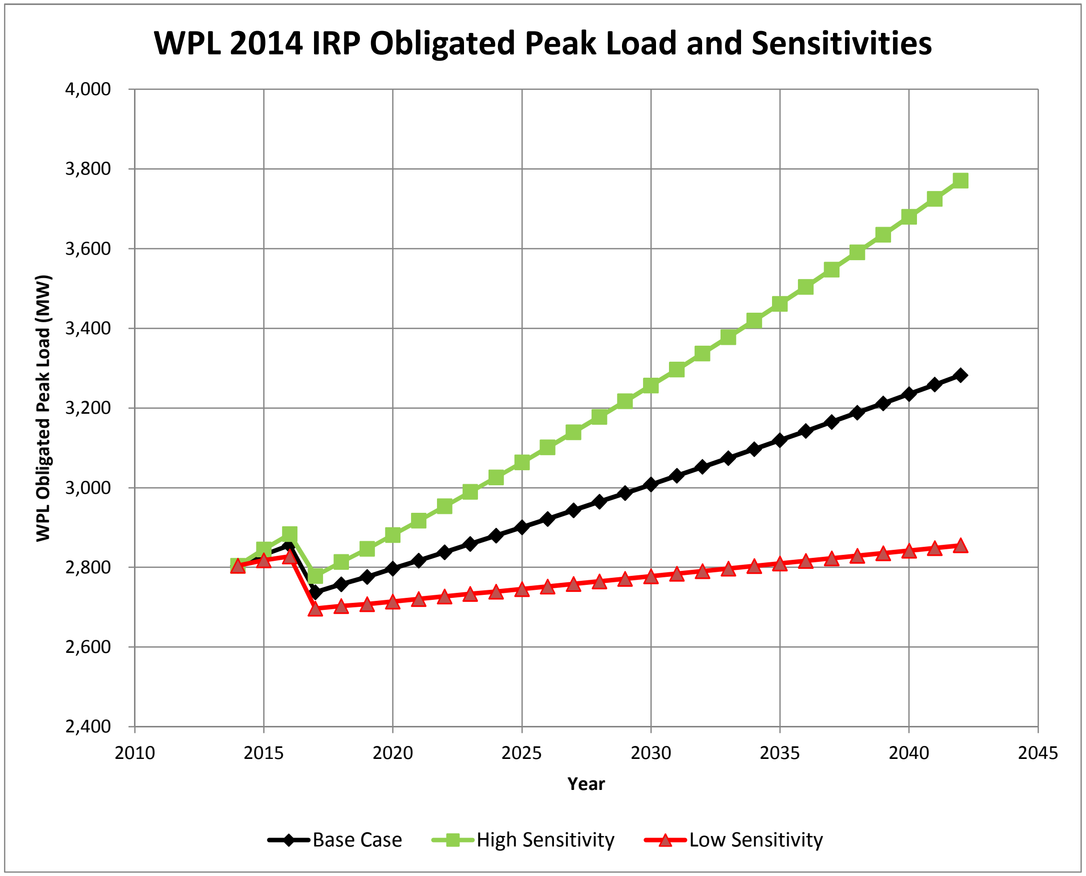
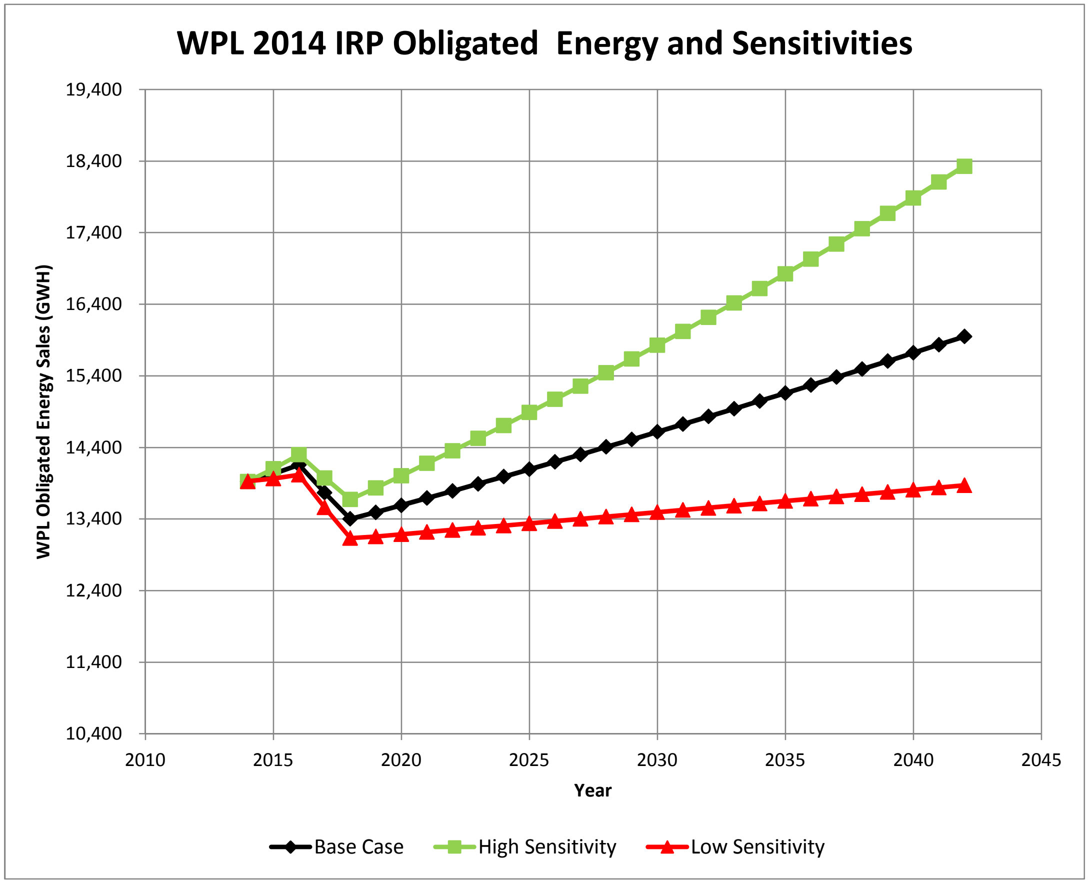


Table 8.3.2.5 WPL 2014 IRP Obligated Energy Sales and Sensitivities

	WPL Obligated Energy Sales (GWH), 2013 P&E		
Year	Base Case	High Sensitivity	Low Sensitivity
2014	13,927	13,927	13,927
2015	14,033	14,103	13,964
2016	14,159	14,299	14,019
2017	13,767	13,976	13,561
2018	13,403	13,676	13,134
2019	13,493	13,836	13,157
2020	13,591	14,006	13,187
2021	13,691	14,178	13,217
2022	13,790	14,353	13,248
2023	13,891	14,529	13,278
2024	13,993	14,708	13,309
2025	14,095	14,889	13,339
2026	14,198	15,072	13,370
2027	14,301	15,258	13,401
2028	14,406	15,445	13,432
2029	14,511	15,635	13,463
2030	14,617	15,828	13,494
2031	14,724	16,022	13,525
2032	14,831	16,220	13,556
2033	14,940	16,419	13,587
2034	15,049	16,621	13,619
2035	15,159	16,826	13,650
2036	15,270	17,033	13,681
2037	15,381	17,242	13,713
2038	15,493	17,454	13,745
2039	15,607	17,669	13,776
2040	15,721	17,887	13,808
2041	15,836	18,107	13,840
2042	15,951	18,330	13,872



Appendix 8B

Wood Mackenzie Forecasts

(*Confidential in its entirety*)

Appendix 8C

EGEAS Model Results Summary

(*Does not contain confidential information*)

Table 8.5.1a WPL 2014 IRP Present Value Revenue Requirements (millions of 2012$) by Sensitivity

Sensitivity Category	EGEAS Case No. B1d_XXX	Case Description	Case Output		Delta from Base	
				WITH EXT		WITH EXT
BASE	_001	Base Assumptions (Reference Case)		10,423		0
Load Growth	_002	High Load Forecast		11,480		1,057
	_003	Low Load Forecast		9,592		(831)
Market Energy and Capacity	_004	No Market Energy		10,606		183
	_005	Available Market Capacity		10,358		(65)
Gas Prices	_006	Gas Prices +10%; On-pk energy Prices +10%		10,742		319
	_007	Gas Prices +20%; On-pk energy Prices +20%		11,052		629
	_008	Gas Prices +30%; On-pk energy Prices +30%		11,358		935
	_009	Gas Prices -10%; On-pk energy Prices -10%		10,086		(337)
	_010	Gas Prices -20%; On-pk energy Prices -20%		9,712		(711)
	_011	Gas Prices -30%; On-pk energy Prices -30%		9,265		(1,158)
Coal Prices	_012	Coal Prices +10%; Around the clock energy		10,709		286
	_013	Coal Prices -10%; Around the clock energy		10,119		(304)
New Gas Unit Capital Costs	_014	New Gas Unit prices +10%		10,530		107
	_015	New Gas Unit Prices -10%		10,316		(107)
PTC	_016	No Production or Investment Tax Credits		10,683		260
Carbon Regulation	_017	CO2 Scenario - Wood Mackenzie		12,388		1,965

Table 8.5.1b WPL 2014 IRP Description of Sensitivity Categories

Sensitivity Category	EGEAS Case No. B1d_XXX	Case Description	Load Forecast	Market Energy Volume	Market Capacity Volume	Market Energy Price On-Peak	Market Energy Price Off-Peak	Natural Gas Price	Coal Price	New Gas Unit Capital Cost	Production Tax Credit (PTC)	WM Carbon Future	RPS Total	RPS Solar
BASE	_001	Base Assumptions (Reference Case)	Base	~5%	0 MW	Base	Base	Base	Base	Base	In	Out	9.28%	0%
Load Growth	_002	High Load Forecast	High											
	_003	Low Load Forecast	Low											
Market Energy and Capacity	_004	No Market Energy		0%										
	_005	Available Market Capacity			150 MW									
Gas Prices	_006	Gas Prices +10%; On-pk energy Prices +10%				+10%		+10%						
	_007	Gas Prices +20%; On-pk energy Prices +20%				+20%		+20%						
	_008	Gas Prices +30%; On-pk energy Prices +30%				+30%		+30%						
	_009	Gas Prices -10%; On-pk energy Prices -10%				-10%		-10%						
	_010	Gas Prices -20%; On-pk energy Prices -20%				-20%		-20%						
	_011	Gas Prices -30%; On-pk energy Prices -30%				-30%		-30%						
Coal Prices	_012	Coal Prices +10%; Around the clock energy					+10%		+10%					
	_013	Coal Prices -10%; Around the clock energy					-10%		-10%					
New Gas Unit Capital Costs	_014	New Gas Unit prices +10%								+10%				
	_015	New Gas Unit Prices -10%								-10%				
PTC	_016	No Production or Investment Tax Credits									Out			
Carbon Regulation	_017	CO2 Scenario - Wood Mackenzie				Carbon Specs	Carbon Specs	Carbon Specs	Carbon Specs		Out	In		

Table 8.5.1c WPL 2014 IRP EGEAS Deployment of Resource Planning Alternatives by Sensitivity Category (The expansion plan is read horizontally for each sensitivity.)

Sensitivity Category	EGEAS Case No. B1d_XXX	Case Description	2:1 NGCC		1:1 NGCC			1:0 CT			Wind									Solar			Biomass	Biogas	APUR	DSM
BASE	_001	Base Assumptions (Reference Case)	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
Load Growth	_002	High Load Forecast	2019		2025	2036	2039	2032	2035	2038	2019	2020	2021	2022	2023	2024	2025	2030	2037	2024	2031	2037			various	2016
	_003	Low Load Forecast	2019	2036							2019	2020	2021	2022	2023	2024										2016
Market Energy and Capacity	_004	No Market Energy	2019	2031				2038	2039		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_005	Available Market Capacity	2019	2035				2039	2040		2019	2020	2021	2022	2023	2024	2028	2041							various	2016
Gas Prices	_006	Gas Prices +10%; On-pk energy Prices +10%	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_007	Gas Prices +20%; On-pk energy Prices +20%	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_008	Gas Prices +30%; On-pk energy Prices +30%	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_009	Gas Prices -10%; On-pk energy Prices -10%	2019	2031				2038	2039		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_010	Gas Prices -20%; On-pk energy Prices -20%	2019		2036	2039		2030	2035		2019	2020	2022	2023	2024	2025									1-2018	2016
	_011	Gas Prices -30%; On-pk energy Prices -30%	2019	2031				2038	2039		2024	2038	2039	2040	2041					2030					1-2018	2016
Coal Prices	_012	Coal Prices +10%; Around the clock energy	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_013	Coal Prices -10%; Around the clock energy	2019		2036	2039		2031	2035		2019	2020	2022	2023	2024	2025	2028	2041		2030					1-2018	2016
New Gas Unit Capital Costs	_014	New Gas Unit prices +10%	2019		2036	2039		2031	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
	_015	New Gas Unit Prices -10%	2019		2036	2039		2030	2035		2019	2020	2021	2022	2023	2024	2028	2041		2030					1-2018	2016
PTC	_016	No Production or Investment Tax Credits	2019	2031				2038	2039		2025	2038	2042							2030					1-2018	2016
Carbon Regulation	_017	CO2 Scenario - Wood Mackenzie	2019	2031				2038	2039		2024	2028	2029	2030	2033	2034	2035	2041		2030					1-2018	2016

See Section 7 of this IRP report for a complete and terse description of each planning resource technology.

Table 8.5.1.d WPL 2014 IRP EGEAS Time Line Reference.

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Study Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30

Appendix 8D

WPL Base, High, and Low Capacity and Energy Forecast

(*Does not contain confidential information*)

Table 8.5.2.1.1 WPL 2014 IRP Base, High and Low Forecasts

	Base Case Forecast			High Forecast Sensitivity			Low Forecast Sensitivity		
Year	Annual Energy (GWh)	Non-Coincident Peak Load (MW)	Obligation MW	Annual Energy (GWh)	Non-Coincident Peak Load (MW)	Obligation MW	Annual Energy (GWh)	Non-Coincident Peak Load (MW)	Obligation MW
2013		2,512	2,753		2,512	2,753		2,512	2,753
2014	13,927	2,548	2,804	13,927	2,548	2,804	13,927	2,548	2,804
2015	14,033	2,585	2,832	14,103	2,599	2,846	13,964	2,572	2,818
2016	14,159	2,619	2,856	14,299	2,646	2,883	14,019	2,592	2,828
2017	13,767	2,634	2,737	13,976	2,675	2,779	13,561	2,594	2,697
2018	13,403	2,654	2,758	13,676	2,708	2,814	13,134	2,601	2,703
2019	13,493	2,672	2,776	13,836	2,740	2,846	13,157	2,605	2,708
2020	13,591	2,692	2,797	14,006	2,774	2,882	13,187	2,612	2,714
2021	13,691	2,712	2,817	14,178	2,809	2,917	13,217	2,618	2,721
2022	13,790	2,732	2,838	14,353	2,844	2,953	13,248	2,624	2,727
2023	13,891	2,752	2,859	14,529	2,879	2,990	13,278	2,630	2,733
2024	13,993	2,772	2,880	14,708	2,915	3,026	13,309	2,636	2,740
2025	14,095	2,793	2,901	14,889	2,951	3,063	13,339	2,642	2,746
2026	14,198	2,813	2,922	15,072	2,988	3,101	13,370	2,649	2,752
2027	14,301	2,834	2,943	15,258	3,025	3,139	13,401	2,655	2,759
2028	14,406	2,855	2,965	15,445	3,062	3,178	13,432	2,661	2,765
2029	14,511	2,876	2,986	15,635	3,100	3,217	13,463	2,667	2,771
2030	14,617	2,897	3,008	15,828	3,139	3,257	13,494	2,673	2,778
2031	14,724	2,919	3,030	16,022	3,178	3,297	13,525	2,679	2,784
2032	14,831	2,940	3,052	16,220	3,217	3,337	13,556	2,686	2,790
2033	14,940	2,962	3,075	16,419	3,257	3,378	13,587	2,692	2,797
2034	15,049	2,984	3,097	16,621	3,297	3,420	13,619	2,698	2,803
2035	15,159	3,006	3,120	16,826	3,338	3,462	13,650	2,704	2,810
2036	15,270	3,028	3,142	17,033	3,380	3,504	13,681	2,711	2,816
2037	15,381	3,050	3,165	17,242	3,422	3,548	13,713	2,717	2,823
2038	15,493	3,073	3,189	17,454	3,464	3,591	13,745	2,723	2,829
2039	15,607	3,095	3,212	17,669	3,507	3,635	13,776	2,730	2,836
2040	15,721	3,118	3,235	17,887	3,550	3,680	13,808	2,736	2,842
2041	15,836	3,141	3,259	18,107	3,594	3,725	13,840	2,742	2,849
2042	15,951	3,164	3,283	18,330	3,639	3,771	13,872	2,749	2,855