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GDS Associates, Inc.

Engineers and Consultants

STATE OF DELAWARE
DIVISION OF THE PUBLIC ADVOCATE

Evaluation of Delmarva Power & Light Company's 2010 Integrated Resource Plan

Docket 10-2

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1 Executive Summary

The Delaware Public Advocate ("DPA") contracted GDS Associates, Inc. ("GDS") to perform a review and evaluation of Delmarva Power & Light ("DP&L" or "Company") Company's Integrated Resource Plan ("IRP" or "Plan"), which was filed with the Delaware Public Service Commission ("PSC") on December 1, 2010. The IRP updates the Company's previous IRP, which was filed in November 2008. Our review focused on the overall strengths and weaknesses of the IRP rather than on specific analysis conducted by the Company.

The purpose of an IRP is to develop a plan for ensuring an adequate supply of power at the lowest reasonable cost. Our review and analysis leads us to conclude that the Company provided a more comprehensive plan than presented in the 2008 IRP, and there is nothing of dire significance that would cause the public to reject the IRP. GDS concludes there are no outstanding issues or upcoming events that carry a high enough probability to derail the IRP as presented by the Company.

Highlighted below is a brief summary of GDS' evaluation of DP&L's performance on development of the IRP.

1.1 Accountability

- DP&L developed an independent load forecast for development of the IRP rather than relying on projections developed by PJM.
- In the reference case, DP&L is totally reliant on capacity constructed by others to meet load growth.
- DP&L relies on the Delaware Sustainable Energy Utility ("SEU") for planning and implementing energy efficiency programs sufficient to meet DP&L's energy and peak demand savings goals. DP&L also conducts its own direct load control programs and is planning dynamic pricing rates through its Automated Metering Infrastructure ("AMI").
- DP&L adhered to the procedural schedule and conducted informal discovery conferences and public workshops to assist parties in their review of the IRP. The Company has attempted to be as transparent as possible in communicating with all parties.

1.2 Completeness

- DP&L's load forecast presents a base case scenario and a sufficient number of alternative scenarios that address uncertainties in the factors impacting peak demand and energy consumption. Therefore, the load forecast is complete for the purposes of integrated resource planning.
- The IRP provides a sufficient level of detail and analysis of supply side alternatives with respect to utility owned generation resources on the Delmarva peninsula.

- DP&L did not evaluate long-term purchase power agreements ("PPA") with regional power generators in detail.
- The IRP includes a number of new energy efficiency measures that have proven to be viable options for other utilities.
- The IRP includes a generally feasible renewable energy plan and demonstrates an awareness of renewable resource options in the PJM region
- With regard to transmission planning, DP&L should coordinate with PJM to examine the impacts on the IRP of potential MAPP delays, treatment of potential generation retirements, and treatment of potential interconnection costs for DP&L generation assets.

1.3 Internal Consistency

- In light of instances where more detailed analyses are recommended, DP&L's analysis is consistent across the load forecast, supply side, and demand side planning functions. We find no egregious errors of being internally inconsistent between the various analyses and sections of the report.

1.4 Clarity

- The 2011 IRP is more fully documented than the 2008 IRP. However, the report still lacks clarity at least in the fact that there is no explicitly self-contained documentation within the report that delineates the projected energy and demand requirements and how those requirements are proposed to be met with demand side and supply side resources. The documentation also lacks detailed discussion of expected savings from Demand Side Management ("DSM") programs.

Recommended courses of action for DP&L are presented in Section 2. Section 3 summarizes the extent to which DP&L responded to the DPA's recommendations in its 2008 IRP evaluation[1]. Sections 4 through Section 8 identify the specific strengths and weaknesses of the IRP and present a description of key issues relating to the load forecast, transmission planning, demand-side planning, supply-side planning, and renewable resources. Section 9 addresses the DPA's conclusions regarding the IRP filing requirements for DP&L.

[1] *State of Delaware, Division of the Public Advocate, Evaluation of Delmarva Power & Light Company Integrated Resource Plan, PSC Docket No. 07-20, May 14, 2009.*

2 Recommendations

GDS makes the following recommendations regarding DP&L's 2010 IRP.

2.1 Load Forecast

- DP&L should develop a more comprehensive reporting of the load forecast, expressly identifying all assumptions, key model inputs, forecasting model specification and outputs, and forecast outputs. The data used to develop the forecasting models should be provided in table form in the report or as an appendix.
- In modeling and projecting residential energy, DP&L should transition from an econometric model to an end-use model or a hybrid end-use/econometric model, which would provide for greater quantification and understanding of the many factors impacting residential consumption.

2.2 Transmission Planning

- The IRP should include a more robust treatment of transmission options, including the cost of transmission capacity needed to meet capacity requirements.
- DP&L should more clearly identify the interconnection costs for new capacity.
- The IRP should present a more robust contingency plan for loss of major transmission facilities.

2.3 Demand Side Analysis

- DP&L should provide more detailed documentation regarding demand side analyses, especially for programs not instituted by the SEU. Documentation should include, at a minimum, key assumptions regarding measure-level energy and demand savings estimates, market adoption rates, incentive levels, and full documentation of benefit and cost assumptions.
- Given the level of DSM impacts assumed, the IRP should include a scenario analysis in which DSM goals are not met to the fullest. A high proportion of estimated savings is based on prospective programs that may not perform as expected. This could be a scenario that would have implications for the supply-side planning.
- DP&L should model the program interactions for its DSM programs to the extent possible when estimating peak demand and energy savings. For instance, direct control program demand savings should probably assume some penetration of the weatherization program; then the dynamic pricing impacts should assume the impacts associated with both direct control and weatherization. DP&L should also fully document the methodologies used to estimate these interactions.

2.4 Supply Side Analysis

- DP&L should provide analytical data in some form to support selection of plans chosen for further analysis.
- DP&L should subject all potential resources to sensitivity analyses based on changes in critical assumptions such as fuel price projections.
- DP&L should provide assumptions used in the modeling of Full Service Requirements Agreements.
- Long term energy supply agreements should be evaluated as part of IRP development.

2.5 Renewable Resources Planning and Analysis

- DP&L should present a complete schedule of sources and uses of RECs and SRECs, with the impact of any multiplier effects for the planned sources and uses as well as contingency sources and uses of RECs and SRECs.
- DP&L should develop more robust contingency plans that address the potential for the offshore wind farm not being built as scheduled. Contingencies should address the issues of PTC expiration and potential transmission constraints on wind projects in PJM, with a focus on developing a portfolio of higher probability wind farm resource options based on market research of developers and potential transmission constraints.
- DP&L should explicitly show all assumptions and calculations that demonstrate how their assumed renewable energy supplies translate to ratepayer impacts on an aggregate and incremental basis.
- DP&L should develop contingency plans to address probabilities of variance in load and/or DSM impacts, explicitly showing the likelihood of those variances and the effect the variances would have on acquiring RECs and SRECs.

3 Status of Prior Recommendations Made by Public Advocate

GDS Associates made a number of recommendations regarding the 2008 IRP filed by DP&L in PSC Docket 07-20. Those recommendations were presented in a report sponsored by the Division of the Public Advocate, dated May 14, 2009[2]. This section revisits the recommendations made by GDS in that report and provides comments on the extent to which the 2010 IRP incorporates or responds to those recommendations.

3.1 Load Forecast

RECOMMENDATION - DP&L should develop a long-term energy and demand requirements forecast for its various customer classes in house and on an annual basis. DP&L can use the PJM zonal projections as a "reasonableness check" on their internally generated forecasts, but they should not rely solely on the PJM projections. This is not an inexpensive endeavor, but should be a component of operational planning for a utility the size of DP&L.

STATUS IN 2010 IRP - DP&L has performed the recommended action. The 2010 IRP includes a load forecast that was developed in house and independently of PJM.

RECOMMENDATION - DP&L should develop full documentation of the forecast, expressly noting all assumptions and key inputs and providing the forecasted outputs.

STATUS IN 2010 IRP - DP&L prepared a load forecast document that was presented as Appendix 3 in the IRP report. While the report provides discussion on procedures and methodologies, DP&L should continue to revise the report by providing greater detail.

RECOMMENDATION - DP&L should conduct a more detailed analysis of the key factors impacting energy and demand. As part of its forecasting process, DP&L should consider economic factors other than employment for forecasting energy consumption. In addition, DP&L should project trends in customer migration and support their forecasted migration rates as part of the assumptions to the forecast.

STATUS IN 2010 IRP - DP&L has performed the recommended action. The load forecast developed by DP&L is based on a more thorough analysis of factors and models than was performed in the prior IRP.

RECOMMENDATION - DP&L should test whether using different weather data for the southern portions of the state (perhaps using Dover or Georgetown data) would better predict load for that portion of its

[2] Ibid.

consumers. The southern portions of the state are more exposed to weather coming off of the Atlantic Ocean. These differing weather patterns impact electricity consumption.

STATUS IN 2010 IRP - DP&L did not address this recommendation.

3.2 Transmission Planning

RECOMMENDATION - DP&L should work with PJM to conduct a more rigorous power flow analysis to show the impact on reliability of the absence of the MAPP Project, the impact on reliability of loss of the MAPP Project and the retirements of Indian River #1 and #2 (and potentially Units #3 and #4), and how the preliminary list of transmission facility upgrades results in a level of reliability that meets or exceeds that of the MAPP Project and results in a similar if not reduced environmental impact on the region.

STATUS IN 2010 IRP – DP&L did include more information regarding the impact of the MAPP Project through highlighting the projects in the PJM RTEP in the IRP. This reliance on PJM strengthened the overall picture of transmission, but GDS still recommends specific power flow-based scenario analysis to determine how specific reliability projects are impacted by the Contingency Plan.

RECOMMENDATION - DP&L should show how generator interconnection costs are factored into the evaluation of possible local generation assets. It is difficult to estimate such costs without knowing the details of the extent of the interconnection and the need for breaker replacements in adjacent stations. Costs could range from a few million to tens of millions of dollars.

STATUS IN 2010 IRP – DP&L continued to roll the costs of generic interconnection facilities into the economic evaluation of potential generation assets. This was not adequately addressed in the current IRP.

RECOMMENDATION - If DP&L has not considered the cost of generation interconnection, DP&L should show the break-even analysis on what level of generator interconnection costs make local generation infeasible.

STATUS IN 2010 IRP - DP&L continued to roll the costs of generic interconnection facilities into the economic evaluation of potential generation assets. This was not adequately addressed in the current IRP.

3.3 Supply Side Options

RECOMMENDATION - DP&L should not rely on PJM's Reliability Pricing Model ("RPM") to encourage new generation resources. Capacity prices, determined by RPM, are not long-term prices and may not be sufficient to induce capital intensive projects. While RPM is presented as a long term capacity process, its auction horizon is three years and thus inconsistent with a planning period of some 10-15 years. In addition, reliance on a regional pricing mechanism may well not be congruent with the stated policy of Delaware taking control of its own energy future.

STATUS IN 2010 IRP - No details were provided in the 2010 IRP that indicate assumptions behind FSA availability or pricing.

RECOMMENDATION - DP&L should conduct a detailed market study to provide more accurate and complete evaluation of a combined cycle resource, including identification of potential sites, availability of gas for the sites, and cost to provide it, transmission system impacts, updated equipment and Engineering, Procurement and Construction (EPC) costs and other cost elements.

STATUS IN 2010 IRP - Analysis of generic combined cycle resources was conducted as part of the IRP process and combined cycle capacity was included in one scenario, but site specific information was not provided.

RECOMMENDATION - In addition to a Combined Cycle or "CC" unit analysis, DP&L should conduct a detailed review of a simple cycle combustion turbine ("CT") plant (~100 MW). Combustion turbine units are much more flexible than combined cycle plants as they can be started and stopped frequently. A CT unit may therefore be the best fit to complement intermittent capacity and energy sources. A full review of potential supply-side resources should include an efficient simple cycle CT — once again with an eye towards the public policy goal of weaning Delaware away from overreliance on the PJM markets.

STATUS IN 2010 IRP - Analysis of generic combustion turbine resources was conducted as part of the IRP process.

RECOMMENDATION - DP&L should identify potential generation sites where internal sources could be located to meet or exceed the reliability and economic benefits of MAPP. Resource supply options should be considered under several carbon tax scenarios to determine the outer boundaries of costs for resources likely to be most cost effective under a reasonable set of carbon tax scenarios.

STATUS IN 2010 IRP - Site specific information was not provided in the IRP. Although the reference case and three scenarios were evaluated under varying carbon tax scenarios, all potential supply-side resources were not subjected to the same type of analysis.

3.4 Demand Side Options

RECOMMENDATION - DP&L should conduct a more thorough analysis of energy efficiency and demand response measures. Projected energy savings appear to be low in its current IRP. . DP&L should reflect the Delaware Sustainable Energy Utility impacts in its next IRP.

STATUS IN 2010 IRP - A much more thorough analysis and description of DSM programs was conducted in the 2010 IRP, at least in part due to the Delaware Energy Conservation & Efficiency Act of 2009. Although the documentation provided in the 2010 IRP is more inclusive than the prior IRP, GDS still recommends that further details be provided for the DSM analysis as described further in this report.

3.5 IRP Documentation

RECOMMENDATION - DP&L should include a section in the document that clearly delineates the projected energy and demand requirements and how those requirements are proposed to be met with demand side and supply side resources. The document should further clearly specify which and how much of each resource is planned to meet projected load.

STATUS IN 2010 IRP - The 2010 IRP main document more clearly summarizes the load forecast, and a technical appendix dedicated solely to the load forecast was prepared in the 2010 IRP. However, the report includes no tables or figures that present projected energy and demand requirements and the portfolio of resources developed to serve those projected requirements.

RECOMMENDATION - The DP&L IRP was difficult to follow and compare various sections and data due to its layout. DP&L should structure the physical layout of the report to better represent information flow and provide a document in which it would be easier to find information relative to a specific IRP topic. At a minimum, topics that should be labeled and identified in the report structure include Executive Summary, Background (or History), Load Forecast, Demand Side Analysis, Supply Side Analysis, Transmission Planning & Reliability Analysis, and Scenario Analysis.

STATUS IN 2010 IRP - The IRP document is laid out in an easier to follow scheme, with sections for each of the critical areas identified in the recommendation above. Additional sections provided in the 2010 IRP that were not recommended but that are important in 2010 include Environmental Externalities and Renewable Resources. There are still some recommendations made in this report regarding documentation and detail, but in general the IRP report is easier to navigate.

4 Load Forecast

4.1 Strengths

The stronger aspects of DP&L's load forecast for the current IRP include:

- DP&L has taken on the responsibility of developing its load forecast rather than using a forecast developed by PJM.
- DP&L follows a bottom-up approach in developing the energy sales forecast by developing models by individual customer class.
- DP&L's source for economic projections, Moody's Economy.com, is a source used by many electric utilities. It is preferable to have economic projections from an independent and reliable source.
- DP&L's blended projection of price (a blend of forward electricity price curves and general inflation) is well designed.
- DP&L clearly identifies and incorporates the impacts of new DSM and energy efficiency programs.

4.2 Weaknesses

- The forecast is developed using econometric models, which provide for the quantification of influential factors. However, use of an end-use model, or a hybrid end-use/econometric model would provide for a greater quantification and understanding of the many factors impacting residential household consumption.
- The load forecast document presented as Appendix 3 in the IRP should provide more detailed discussions and explanations regarding processes, assumptions, and results.

4.3 Key Issues

4.3.1 Development of an Independent Load Forecast

In its 2009 report, the DPA criticized DP&L for relying on a load forecast prepared by PJM and recommended that the Company develop its own long-term energy and demand requirements forecast in-house and on an annual basis[3]. In conjunction with the development of its IRP, DP&L developed an independent load forecast. Results of the forecast are summarized in Section 3a of the IRP report, and a more detailed report addressing the load forecasting process and results is presented as Appendix 3 in the final 2010 IRP report.

[3] Ibid.

4.3.2 Forecast Approach

In its 2009 report, the DPA recommended that DP&L employ a bottom-up forecasting approach[4]. As described in the IRP Appendix 3, Section I.C, DP&L developed the retail energy sales forecast at the class level (Residential, Commercial, and Industrial). Peak demand is modeled at the Delmarva zone level only. This bottom-up approach to modeling energy sales (i.e., by retail customer class) provides for a more thorough quantification of the many factors impacting energy sales and for greater transparency in DP&L documenting and presenting the forecast. Unfortunately, DP&L provides no documentation or exhibits for the retail customer class models.

In addition to the models developed at the retail customer class level, DP&L models energy at the Delmarva jurisdictional and zone levels, as described in the IRP Appendix 3, Section IV. Total jurisdictional energy and zonal peak demand are broken down to the retail customer class level using sharing techniques, which should be described in greater detail in future reports.

There is no apparent discussion of whether the energy forecast supporting the IRP is based on the individual retail class models, the jurisdictional or zonal models, or some combination of the two separate modeling approaches. Future load forecast reports should provide more specifics regarding the relationship between the retail energy models and the jurisdiction and zone models, and how the results from each are represented in the final total energy forecast.

4.3.3 Forecasting Model Specifications

There is no discussion of the customer class energy sales model inputs and no presentation of the associated model parameters and statistics. In future reports, DP&L should include this information; otherwise, it is impossible to evaluate the theoretical consistency and statistical validity of the models. It is not clear if the residential sales forecast was developed at the total class sales level or as the product of number of residential customers and average kWh per customer. To maximize the number of relevant factors impacting total residential sales, the sales forecast should be based on projections of both number of customers and use per customer.

While econometrics has been a common method of forecasting energy sales, end-use models, or hybrid end-use/econometric models provide a better means for analyzing and projecting residential sales because of the large number of key inputs the models can include. While traditional econometric models include an economic variable, price, weather, and electric appliance market shares, end-use approaches address these factors plus appliance efficiencies, housing characteristics, householder characteristics, and federal appliance standards.

4.3.4 Economic Outlook

The economic outlook used in development of DP&L's load forecast was obtained from Moody's Analytics. Moody's is an independent provider of economic data and forecasts, and their outlooks are used by many utilities in the U.S. DP&L does not present the economic outlook as part of its load

[4] Ibid.

forecast documentation. Future reports should include a table presenting historical and projected values for the specific economic variables used to develop the forecasting models.

4.3.5 Forecast Results

DP&L presents the energy and peak demand forecast in tabular and graphic form in the main body of the IRP report and in greater detail in Appendix 3 of the report. Forecast scenarios are presented graphically, but not in tabular form. The average annual compound growth in energy sales is consistent with forecasted growth rates for the nation and the Mid-Atlantic region as projected by the Energy Information Administration.[5]

DP&L's load forecast document excluded any discussion on two key findings. One, there is a considerable drop in Delmarva zone peak demand, 130 MW, in 2012. A decrease in peak load of this magnitude calls for an explanation. Two, projected load factor declines significantly over the forecast horizon, indicating peak demand is projected to increase at a much higher rate than energy sales. Any large differences between the projected growth rates of energy sales and peak demand should be explained thoroughly, including specific reasons or events.

[5] Department of Energy, Energy Information Administration, 2011 Annual Energy Outlook, April 26, 2011

5 Transmission Planning

5.1 Strengths

- The transmission plan and potential issues regarding transmission are more fully addressed in the 2010 IRP than in the 2008 IRP
- The PJM Regional Transmission Expansion Plan (RTEP) process[6] is a robust process and allows for major changes in transmission topology and generator status to be addressed on a regional basis.

5.2 Weaknesses

- The transmission plan fails to consider access to existing power supply resources outside the DP&L area.
- The IRP report fails to clearly identify existing and future transmission projects, as there are inconsistencies between projects listed in specific tables and figures in the IRP report.
- DP&L should more clearly address treatment of transmission risk in the IRP report.

5.3 Key Issues

5.3.1 Changes from the 2008 IRP

The DP&L 2010 IRP has included the effects of transmission in two distinct areas: resource plan development and demand side management activities. The impact of the transmission expansion plan can have a significant effect on the consideration of supply side options. The 2010 IRP is a marked improvement over the 2008 IRP with respect to the treatment of transmission. Page 35 of the IRP that discusses major departures from the 2008 IRP identifies "an analysis using the latest PJM RTEP results."

5.3.2 PJM Regional Transmission Expansion Plan (RTEP)

The PJM Regional Transmission Expansion Plan (RTEP) process[7] is a robust process and allows for major changes in transmission topology and generator status to be addressed on a regional basis. DP&L transmission planners coordinate with the PJM transmission planners to develop the PJM Regional Transmission Expansion Plan ("RTEP"). The RTEP results in a list of transmission projects that are designed to meet applicable North American Electric Reliability Corporation (NERC), Reliability First Corporation (RFC), PJM, and DP&L local planning criteria.[8]

[6] PJM Manual, Section 14-B
[7] PJM Manual, Section 14-B
[8] 2010 IRP Section 3c, p. 98.

DP&L has already benefitted from the feedback from the RTEP process in the treatment of the PATH project. DP&L delayed the filing of the 2010 IRP to reflect the withdrawal of PATH project from the RTEP. The IRP also included the latest in-service date change for the Mid-Atlantic Power Path (MAPP) project to 2015. Additionally, since the RTEP is performed on an annual basis, any changes to bulk transmission projects, such as MAPP, impact load flow and therefore result in changes in load flow to the lower voltage reliability-based projects. The projects identified in the IRP appear to adequately address the delayed in-service date of the MAPP project.

5.3.3 Transmission Impacts of Existing and Potential Power Supply Projects

The treatment of transmission has been more geared to the impacts on potential power supply projects and energy efficiency improvements, but does not consider access to existing power supply resources outside the DP&L area. The IRP states that "Delmarva will evaluate generation, *transmission* and demand-side resource options during the planning period to ensure that sufficient and reliable resources to meet customer needs are acquired at a reasonable cost."[9] In the power supply resource evaluation, transmission interconnection costs are embedded within the capital costs for new resources. Also, generic transmission upgrades are referenced, but this appears to be inconsistent with a market-based system that relies on differences in location to differentiate prices for resources. Sections 3.1.1 and 5.3 of the IRP regulations are met because the RTEP is now considered, but the failure to more thoroughly consider transmission options as a replacement for displacing other existing capacity alternatives should be noted.

5.3.4 Reporting of Expansion Plan

One of the strengths of the 2010 IRP is the use of the latest RTEP projects; however, the IRP filing puts forward several sets of transmission projects that to not appear to synch up. There is an inconsistency between transmission projects listed on Table 6 (pp 25-26), Table B.11 (pp 81-82), and Figure 1 (p 99)/Figure 2 (p 100). Since the project lists do not match up, it is difficult to tell what the true expansion plan is, what projects were added in the past, and if the calculations of system loss reductions are reasonable.

5.3.5 Treatment of Transmission Risk

Each section of the IRP has a section labeled "Contingency Planning" in accordance with Section 3.2.7 of the IRP Regulations. The purpose of this section is to address what would happen "should one of the supply, demand, or *transmission options* be either delayed or not realized." The transmission Contingency Plan is as follows:

"The PJM RTEP considers the five year needs of the regional transmission system and is updated on an annual basis. As new decisions are made during the RTEP process, Delmarva updates its plans accordingly."

[9] 2010 IRP, p. 23.

This plan is in stark contrast to the Contingency Plan descriptions in the other options in the 2010 IRP. DP&L relies solely on the RTEP to address any potential delays. It has previously been discussed regarding the benefit of the joint coordinated planning between DP&L and PJM, but given the fact that DP&L specifically requested and received a delay in the filing of this IRP, DP&L seems to be taking a much more relaxed stance on the potential delay or non-realization of the MAPP project.

6 Demand Side Analysis

6.1 Strengths

- Collaboration with the Delaware Sustainable Energy Utility ("SEU"). The SEU specializes in selecting and designing effective energy efficiency programs. DP&L will be able to leverage that expertise.
- A large portfolio of energy efficiency, direct load control, and dynamic pricing programs is planned for implementation by DP&L. A diverse portfolio of programs helps hedge against the impacts on the system of imperfections in a single program (e.g., market penetration rates that come in much lower than expected).
- Direct load control programs are estimated to have excellent economics.
- Implementation of dynamic pricing makes good use of AMI systems.

6.2 Weaknesses

- Insufficient documentation on energy efficiency and demand response potential analyses.
- Dependence on prospective SEU programs to meet shortfalls in DSM savings requirements.
- No serious consideration given to a scenario in which DSM goals are not met. The contingency planning if DSM goals and requirements are not met is weak.
- Unclear if interactions between various programs are accounted for.

6.3 Key Issues

6.3.1 Documentation of DSM Analyses

There is insufficient documentation of the potential analyses conducted for energy efficiency and demand response programs. For energy efficiency programs, reliance on the SEU may make documentation of specific assumptions more difficult. However, DSM analysis in the IRP should probably include critical assumptions such as per unit energy and demand savings, assumed penetration rates, and key program costs and benefits. The IRP does provide some explanation of the new dynamic pricing program. However, there is no documentation supporting the benefit-cost analysis of direct load control programs.

6.3.2 Collaboration with the SEU

DP&L is required by Delaware State Code 26 Del. C. § 1020 to collaborate with the SEU in promoting energy efficiency programs and measures for DP&L's customers. It is not clear from the information presented in the IRP how DP&L is collaborating with the SEU and it appears all program direction comes solely from the SEU without input from DP&L. This agreement set forth in 26 Del. C. § 1020 states:

"Demand-side management and other energy efficiency activities shall be implemented by the SEU (as defined in §8059 of Title 29), in collaboration with the utility." The IRP identifies specific rebates and other programs currently being offered by the SEU to DP&L customers. The IRP also states that these programs are "subject to impacts of the current economy such as slow participation rates." DP&L's ability to meet the goals specified in the IRP is greatly impacted by the work of the SEU. As such, it is difficult to gauge if the programs being designed and implemented by the SEU will achieve the participation and electricity savings results expected for future periods of the IRP.

6.3.3 Cost Effectiveness of Direct Control Demand Response Programs

Although there is insufficient detail to verify the benefit-cost analyses for demand response, the results for direct control programs indicate these programs are beneficial[10]. The residential and non-residential direct control programs have total resource cost benefit-cost ratios of 6.8 and 25.4, respectively. These very high ratios mean that, should program adoption rates underperform expectations in the early years of the program, then there is "headroom" available to increase incentive levels as a way to encourage more participation. These highly cost effective programs also mean that they should provide significant cost savings to DP&L relative to cost and therefore provide a benefit to DP&L's consumers.

6.3.4 Dependence on Prospective SEU Programs

In order to show DSM impacts that meet the requirement of the Delaware Energy Conservation & Efficiency Act of 2009 ("the Act"), DP&L relies on a significant portion of SEU prospective programs. Two of the programs are expansion of current programs and two are prospective. The Combined Heat and Power ("CHP") program and the Sustainable Communities program have not yet been designed. Failure to develop these prospective programs, or to obtain sufficient funding, would mean that DP&L would fall short of their expected DSM goals.

DP&L performed a separate detailed market analysis for CHP programs and indicated in its IRP that if the SEU does not pursue implementation of a CHP program, then DP&L may propose a plan for approval by the Public Service Commission for a program.[11]

The prospective programs represent a significant portion of the expected DSM savings. The CHP impacts represent 15% of total DSM energy savings in 2015 and 21% of total DSM savings in 2020. It also represents 6% of 2015 peak demand savings and 10% of 2020 peak demand savings.

The prospective programs excluding CHP are expected to provide for 32% of the expected 2015 energy savings and 20% of demand savings for DSM programs. By 2020, these programs represent 19% of energy savings and 16% of demand savings. Combined with the CHP program, these programs that are not yet proven represent a significant portion of the expected DSM impacts:

[10] Refer to page 74 of Delmarve Power & Light's *2010 Integrated Resource Plan*, which indicates Residential Load Control has a benefit-cost ratio of 6.8 (benefits exceed costs by nearly 7 times) and non-Residential Load Control has a benefit-cost ratio of 25.4.
[11] Delmarva Power & Light. *2010 Integrated Resource Plan*. Page 66, Footnote 27.

- 47% of energy savings in 2015; 29% of demand savings in 2015
- 39% of energy savings in 2020; 26% of demand savings in 2020

6.3.5 Scenario Analysis of Not Meeting DSM Goals

The IRP does not run any analyses that contemplate the impacts of not meeting the DSM goals. Savings of 15% of energy sales and peak demand by 2015, specified in the Act, are very aggressive goals. If those goals are unmet, the contingency plan described by the IRP is not sufficient enough an assessment of how such a shortfall may impact supply-side planning. The contingency plan is that the Act permits an additional Energy Efficiency Charge that can be collected to assist in achieving goals. The Act limits the average monthly residential impact of such a rate, however, to $0.58. There is no analysis of what charge may be necessary and how those charges may impact penetration rates and energy requirements. Furthermore, DP&L states they will initiate working groups to discuss revisions to the DSM plans. It may take some time, however, to research, analyze, design, and implement solutions. There would also need to be some time to accumulate the revenue required through the additional energy efficiency surcharge in order to have funds available to effect change. The delay in achievable savings could be considerable after such a contingency plan is put into action.

6.3.6 Capture of Program Interactions in Savings Estimates

There are no clear indications in the IRP that the savings estimates for the various DSM programs appropriately handle program interactions. For instance, do the residential direct control programs take into account that demand savings may be reduced over time due to the Delaware Weatherization Assistance Program? These various interactive effects, if not accounted for, would reduce the estimated savings from DSM programs and force the plan into the contingency mode described above.

The IRP explains that the dynamic pricing impact analysis ignores the effects of other direct control and energy efficiency programs.[12] Since the critical peak pricing periods are likely to coincide with direct load control hours[13], the dynamic pricing impacts are likely overestimated in the study. The Company addresses this issue by stating, on page 78, "...if reductions from other sources are not achieved, demand reductions from dynamic pricing would be expected to be higher". . However, the Company provides no details regarding the extent to which the increases in dynamic pricing program impacts would offset the reductions that are not achieved from other sources.

6.3.7 Comparison of Achievable Reductions in Energy and Demand

The Energy Information Administration Form 861 database includes detailed information for each utility in the United States for peak load, generation, electric purchases, sales, revenues, customer counts, kWh and kW savings of DSM programs, green pricing and net metering programs, and distributed generation capacity. DP&L ranks 200 out of 310 reporting utilities regarding their 2009 energy efficiency savings as a percent of annual kWh sales. Other investor owned utilities in the region rank higher:

[12] Delmarva Power & Light. 2010 *Integrated Resource Plan*. Page 78.
[13] Delmarva Power & Light. 2010 *Integrated Resource Plan*. Page 31.

Connecticut Light and Power ranks 35, Baltimore Gas & Electric ranks 193, and Consolidated Edison Co-NY ranks 193. In terms of cumulative annual kWh savings as a percent of annual sales in 2009, DP&L ranks 175 out of 248 reporting utilities. Once again, other investor owned utilities in the region rank higher than DP&L: Connecticut Light and Power ranks 4, Baltimore Gas & Electric ranks 48, and Consolidated Edison Co-NY ranks 114. It should be noted, however, that savings generated by the SEU, which began in 2009, would not be reported by DP&L and thus savings for Delaware may be higher than would appear from these rankings.

7 Supply Side Analysis

7.1 Strengths

- The IRP included the evaluation of a number of supply-side alternatives.
- A detailed modeling process was used in the production of the IRP.
- Supply-side resources were modeled using reasonable cost and operational characteristics.

7.2 Weaknesses

- Quantitative data to support case selection were not provided.
- Reference case and alternative cases were selected without sensitivity analysis of major assumptions.
- Assumptions related to Full Service Requirements Agreements were not included in the IRP.
- Long term energy supply agreements were not evaluated.

7.3 Key Issues

7.3.1 Reference Case and Alternative Case Selection

Quantitative data were not provided to support the selection of the reference case and three alternative scenarios as the appropriate portfolios subjected to further analysis. Ideally, the IRP process should include an evaluation of all potential resource alternatives under several scenarios defined by different critical data points, e.g., high and low forward market price curves, and high and low natural gas price forecasts. It appears that DP&L's selection of the reference and alternate scenarios was based on one discrete set of baseline assumptions. Although volatility in baseline assumptions was addressed in the Portfolio Modeling process, the scenarios were defined prior to that step. Defining several future resource portfolios under changing conditions, and then subjecting those plans to a Monte Carlo analysis of key variables, would provide assurance that the selected plans are the best choices under varying cost and operational scenarios and meet DP&L's customers' needs at lowest reasonable cost.

7.3.2 Assumptions Related to Full Service Requirements Agreements

Assumptions related to Full Service Requirements Agreements are not included in the IRP. The IRP implies that certain changes were made with respect to how FSAs were considered in the development of the IRP. It is not clear, however, how these changes were quantified and reflected in the assumptions underlying the Full Service Requirements Agreements contained in the IRP plan.

Evaluation of long term energy supply agreements

The IRP references the possibility of entering into long term energy supply agreements and notes that an appropriate cost recovery mechanism would need to be implemented should such arrangements be made. It appears as though, however, that potential long term agreements were not evaluated as part of the IRP process.

7.3.3 Comparison of Reference Case to Other Potential Portfolios

No metrics are included in the RFP (beyond isolated costs associated with discrete potential supply-side resources) that show how costs associated with the reference case compare to any portfolios other than the three scenario cases. No discussion is provided to demonstrate how the reference case and three scenarios were chosen for further analyses, e.g., present value of costs or a combination of present value of costs and annual cost values.

8.3 Key Issues

8.3.1 Renewable Energy Credit (REC) and Solar REC (SREC) Accounting

The IRP presents the planned demand for RECs and SRECs over the period. DP&L is expected to supply retail electricity in compliance with the Delaware Renewable Portfolio standard to SOS customers. SOS customers are expected to account for about 52 percent of load in 2011 and about 54 percent of load in 2020. Although the IRP states that the REC total will be ample to meet the expectation of the RPS, DP&L fails to include three key points in its presentation:

- The status of any existing non-SEU banked RECs and their intended use,
- The schedule of planned banked or bankable RECs generated in 2011 or later, and
- Whether they used the appropriate Delaware RPS multiplier factors in estimating REC supply sources and subsequent REC generation. In informal discussions, however, Delmarva representatives have clarified that the appropriate multipliers were used.

A more robust explanation of RECs and SREC accounting may help clear up specific measurement issues which may also bring to light the risk of significant over or under supply of RECs and SRECs. A full explanation of banked, bankable, and planned use for these banked RECs and SRECs should be made explicit.

8.3.2 Reliance of the Offshore Wind Project to Generate RECs

Delmarva's discussion of RECs arising from the Blue Water Wind project is unclear in the IRP. The use of the 3.5 multiplier is not explained relative to energy purchases and REC contracts. While Delmarva representatives have clarified this issue in discussions, we recommend that Delmarva include clear and explicit language regarding the disposition of capacity, energy, and REC purchases arising from the Blue Water Wind project in its next IRP.

8.3.3 Reliance on Specific Wind Farms in the PJM Territory

While wind energy is the most reasonable renewable energy source to meet the bulk of the RPS requirement, there are risks that have not been discussed or quantified in the IRP. These risks are as follows:

- No analysis of transmission access or future curtailment has been presented for discussion or otherwise addressed. PJM is experiencing rapid build-out of wind capacity in response to many state RPS requirements. DP&L does not consider the risk of future transmission access for current or future wind farms. Curtailments of wind energy are becoming more common in ISOs with higher penetration rates of wind energy. Curtailments could result in a shortfall of expected wind production. A wind project in Minnesota has recently lost 50 percent of its potential energy production due to transmission related curtailments.
- The current plans for PJM sited wind projects shows a high number of interconnection queue studies, but many of these projects may prove infeasible and ultimately not move forward. The

8 Renewable Resources Planning and Analysis

8.1 Strengths

- DP&L has demonstrated a generally feasible renewable energy plan and shown an awareness of supply options in the PJM region.
- DP&L has shown awareness of construction risk in the development of renewable energy projects as a point of concern driving the need for developing supply alternative plans.
- DP&L has shown a close coordination with the Sustainable Energy Utility (SEU). The SEU is expected to be a major provider of Solar Renewable Energy Credits (SRECs).

8.2 Weaknesses

- DP&L has not presented Renewable Portfolio Standard (RPS) plans in a way that brings assurance that they will avoid significant underage or overage levels of RECs or SRECs. For non-solar RECs, it appears that a surplus will be created. If DSM goals are not met, the surplus would be reduced. For SRECs, there is a heavy reliance on the SEU, with arrangements and rules still be planned and with a large SEU ramp-up expected through the IRP time period.
- The IRP does not address significant wind energy supply risks that would lead to an underage of RECs in the second half of the IRP timeframe. Given development and construction timelines, this could pose a risk to meeting RPS requirements. This issue can be mitigated through the purchase of PJM-based RECs, but the IRP has limited discussion of issues associated with this strategy.
- Exhibit 2.4 in Appendix One seems to indicate fairly high capacity costs for onshore wind and solar projects. These costs are in excess of general market conditions, with the underlying information source not presented. It is unclear how these costs may be filtering into rate impact analyses or the comparison of different renewable supply options.
- Information regarding the disposition of REC and SRECs for SOS customers is unclear. Discussions with DP&L clarified the issues for REC accounting, but the IRP document does not explicitly state the assumptions regarding REC and SREC supplies for SOS customers.
- The IRP presents a heavy reliance on the SEU. Although DP&L acknowledges that there is risk to the SEU plans not bearing fruit, the alternative options are not presented, other than the mention of past banked SRECs. The ramp-up of programs that would account for an SEU shortfall would need to happen rapidly.

IRP provides general statements about the ability for DP&L to obtain additional wind capacity, but with no discussion or consideration for specific supply issues.

- Other states' utilities will want wind energy, too. Many states in the PJM territory have RPS requirements. In future years those utilities will be seeking ever greater amounts of wind generation. Competition from other utilities may limit or drive up the cost of future wind supply options.

8.3.4 Production Tax Credit (PTC) Risk

The current PTC and ITC conversion is driving much of the current wind project build-out. Developers can afford to take on greater risks with developing projects due to the PTC/ITC effects. The current PTC and ITC conversion will end starting in 2013. As a result, many potential developments are likely to not move forward or would require greater certainty and higher prices in contracts to justify development. The result could be a significant shrinking of the potential PJM supply options for wind energy projects.

8.3.5 Timelines

If any wind capacity shortfalls occur, these shortfalls may not allow for adequate adjustments for new developments or REC contracts. Key development milestones and trigger issues for regulatory or market conditions that could lead to shortfalls are absent. Without these milestones or trigger issues at the ready, DP&L may not have the internal planning metrics to identify the issues and adjust plans in time to avoid penalties.

Taken individually or together, these risks of a constrained PJM wind supply are significant, particularly if the offshore wind project does not move forward. The outcome could be an underage of RECs or a need to pay higher prices for RECs or wind supply that initially planned.

8.3.6 Changes to the SOS Customer Load

If DP&L loses more SOS customer load than expected, or gains back more SOS customer load than expected, the result could create a proportional overage or underage of RECs or SRECs. The larger REC market does allow for some mitigation of this risk, but it is a risk nevertheless that has not been clearly addressed in the plan for obtaining RECs. In the event that there is an unexpected SOS load loss, there is a risk to current SOS customers. If the other retail suppliers do not purchase DP&L RECs due to lower price options, the remaining SOS customer may end up paying for renewable capacity that is not needed to meet the RPS.

8.3.7 Reliance on the SEU for SRECs

The status of SEU SRECs is still being considered. Although DP&L does have an agreement for reclaiming banked SRECs, DP&L has not presented a clear plan for addressing the long term direction or contingencies. The 10 MW Dover SUN Park will provide 70 percent of its generated SRECs to DP&L. The specific forecast generation from this facility is not presented as a line item in the IRP, but is blended with SEU banked credits. While this project can be expected to provide SRECs in a significant quantity in early years, it will still not meet all of the SREC requirements in the RPS, with ramp-up demands requiring significant new capacity. There is very limited discussion in the IRP that addresses this issue or alternative plans.

8.3.8 Interactions with DSM Effects.

If DSM efforts planned by DP&L do not result in as significant an effect as expected, REC and SREC needs would be higher than planned.

9 Frequency of IRP Filing

Regulated utilities in Delaware are required to file updated IRP reports every two years. There are currently 27 states in the U.S. that have IRP filing requirements[14]. Of this total, 14 must file every two years, 11 file every three years, 1 files every 4 years, and 1 files every 5 years. Of these 27 states, only three are deregulated: Delaware, Oregon and Vermont.

A number of states repealed IRP requirements as the electric utility industry restructured. In some instances, development of procurement plans was instituted. Like IRPs, procurement plans are developed and filed periodically, but procurement plans are designed for utilities that own no generation and operate in deregulated markets. Such plans focus on the evaluation of purchases for capacity and energy, while considering potential impacts of energy efficiency and demand-side programs.

Development of an IRP or a long-term procurement plan requires a significant amount of time and expertise; however, the time and effort required to develop a procurement plan appears to be less extensive than that for an IRP. DP&L determined in its current and previous IRPs that it was most reasonable to meet its energy and peak demand requirements through a series of Full Service Agreements (FSA) for its Standard Offer Service customers. While the Company's strategy for meeting load in the future may change in future IRPs, it can be argued that DP&L's procurement strategy is stable and that development of a long-term procurement plan may be more appropriate for the Company than development of an IRP. As noted above, Delaware is one of only three states where the electric utility industry has been restructured and utilities must develop an IRP. The DPA would support DP&L filing a long-term procurement plan rather than an IRP, or at the very least, revising DP&L's IRP filing requirement from once every two years to once every three years.

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[14] Synapse, *A Brief Survey of State Integrated Resource Planning Rules and Requirements*, Prepared for the American Clean Skies Foundation, April 28, 2011