BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of the Ohio	**)**	
Edison Company, the Cleveland Electric	**)**	
Illuminating Company and the Toledo Edison	**)**	**Case No. 14-1297-EL-SSO**
Company for Authority to Provide for a Standard	**)**	
Service Offer Pursuant to R.C. 4928.143	**)**	
In the Form of an Electric Security Plan	**)**	

Rehearing Testimony of Tyler Comings

Redacted Version

On Behalf of
Sierra Club

June 22, 2016

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List of Exhibits:

Exhibit TFC-46: Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan (Dominion IRP), Before the Virginia State Corporation Commission and North Carolina Utilities Commission, April 29, 2016, *available at* https://www.dom.com/library/domcom/pdfs/electric-generation/2016-irp.pdf?la=en.

Exhibit TFC-47: ICF, The Future of Fuel: Opportunities in an Evolving Global Market, March 25, 2016, *available at* http://www.icfi.com/insights/white-papers/2016/the-future-of-fuel.

Exhibit TFC-48: EIA, Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases, May 17, 2016, *available at* https://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf.

Exhibit TFC-49: PJM Clean Power Plan Modeling: Preliminary Phase 1 Long-Term Economic Compliance Analysis Results, May 6, 2016, *available at* http://www.pjm.com/~/media/documents/reports/20160506-pjm-clean-power-plan.ashx.

Exhibit TFC-50: PJM, 2019/2020 RPM Base Residual Auction Results, *available at* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Tyler Comings. I am a Senior Associate with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts.

Q Are you the same Tyler Comings who filed direct testimony in this matter on December 22, 2014, supplemental testimony on May 11, 2015, second supplemental testimony on October 13, 2015, and third supplemental testimony on December 30, 2015?

A Yes.

Q What is the purpose of your rehearing testimony?

A My rehearing testimony addresses the Companies' modified Rider RRS proposal ("the proposal"), which was filed on May 2, 2016. I show that this proposal will likely cost ratepayers substantially. The Companies' original filing was almost two years ago and since then they have failed to update critical assumptions—including those produced by their own consultant.

Q Are there any exhibits that accompany your testimony?

A Yes. I am attaching Exhibits TFC-46 to -50.

II. SUMMARY OF TESTIMONY

Q Please summarize your rehearing testimony.

A My testimony shows the following key points:

1. This proposal is risky and will likely lead to higher costs for Ohio ratepayers. While the costs of the proposal are now fixed for the eight-year term, the revenues generated will vary with actual energy and capacity prices. If the uncertain revenue does not outweigh the guaranteed costs, then ratepayers lose. This scenario is highly likely given that the

Companies' two-year old energy and capacity price expectations are unreasonably high when compared to more recent price forecasts—including those from the Companies' own consultant.

2. The Companies' natural gas price forecast is stale and inflated. The ICF forecast used in the filing predicted prices that are more than double the prices so far in 2016 (see CONFIDENTIAL Table 1). Since the filing, ICF has developed lower natural gas price forecasts. Yet, the Companies have failed to use this information. This omission significantly inflates the value of the proposal.

3. Because energy prices are highly correlated with natural gas prices, the former are also stale and inflated. Using a recent PJM energy price forecast results in [redacted] (compared to the Companies' estimate of a $260 million benefit).[1] This shows the substantial risk that ratepayers will be subjected to if, as PJM has recently forecast, energy prices are [redacted] than what the Companies assumed two years ago.

4. The capacity prices assumed in the filing are also stale and inflated. Using actual prices through the 2019/2020 delivery year and the more recent ICF forecast for the later years reduces the projected benefit by [redacted] (compared to the Companies' estimate of $260 million). This shows the substantial risk that ratepayers will be subjected to if, as ICF forecast in fall of 2015, capacity prices are [redacted] than what the Companies assumed two years ago.

[1] In my testimony, reported "benefits" and "costs" of the proposal are in terms of net present value (NPV) over the eight-year term.

5. Combining the effects of up-to-date capacity and energy price forecasts leads to an almost $1.6 billion NPV cost to ratepayers. The potential costs of the proposal are too large for the Companies to continually fail to update key assumptions.

II. THE PROPOSAL STILL PASSES ON SUBSTANTIAL RISKS TO RATEPAYERS AND THEY WILL LIKELY LOSE IF IT IS APPROVED

Q How will the value of the transaction be determined?

A As with previous versions of the Rider RRS, ratepayers will receive a credit if the revenues outweigh the costs or they will get charged if the costs outweigh the revenues. However, under the new proposal, the projected levels of generation, capacity, and total costs are fixed for the eight-year term. Revenues will be calculated using the actual prices for energy and capacity.

Q What is the value of the proposal using the Companies' assumptions?

A The Companies' projected value of the transaction is $260 million net present value (NPV). This value represents the difference between the Companies' projected revenues and costs, both of which are substantial amounts: $8.4 billion in NPV revenues and $8.2 billion in NPV costs (shown in Figure 1).[2] A $260 million net benefit represents only a 3 percent margin—i.e., estimated revenues are only 3 percent higher than costs. Therefore, even a slight overestimate of revenues would lead to net costs for ratepayers under this proposal.

[2] These can be calculated using the values provided in SC Exhibit 89 by discounting each year's "Projected Market Revenue" and "Projected Costs" using the "WACC" (weighted average cost of capital) of 7.46 percent.

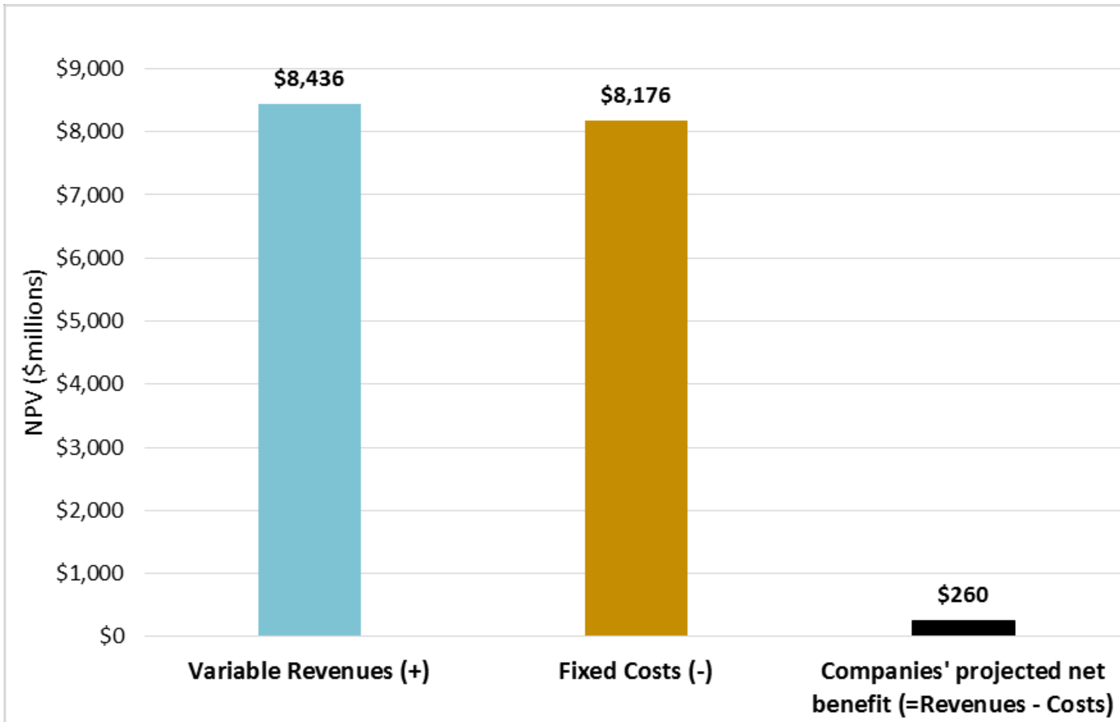


Figure 1: Companies' Projected Revenues and Costs ($NPV, billions)

Q Does the Companies' proposal still subject ratepayers to significant risks?

A Yes. While the over $8 billion NPV in costs that will be factored into the proposal are guaranteed, the revenue that will be credited is highly uncertain. The Companies' revenue estimates (shown above) are comprised of [redacted] NPV in energy revenue and [redacted] NPV in capacity and ancillary services revenue. The actual revenues collected, however, will vary with actual energy and capacity prices–even though the levels of energy (MWh) and capacity (MW) remain fixed. If the uncertain revenue credited to ratepayers does not outweigh the guaranteed costs assumed in the transaction, then ratepayers lose. As I will show, this is likely to happen. In fact, using a more recent energy price forecast from PJM and a more recent capacity price forecast from ICF shows that customers would lose money under Modified Rider RRS. Ratepayers are still subject to a risky transaction and will likely face increased costs over the eight-year term if the proposal is approved.

Q Have the Companies updated their energy and capacity price assumptions since the filing from 2014?

A No. As I have discussed in previous testimony, the original transaction transferred all of the costs of the plants and the market risks onto ratepayers. Because the costs of running the plants are fixed, the latest proposal removes risks that costs of running the plants will be higher than the Companies projected. However, the risk that higher energy and capacity prices will not materialize remains.

Both actual and forecasted energy and capacity prices are already lower than what the Companies' projection relies on. Also, forecasts of future natural gas prices, energy prices, and capacity prices continue to be lower than the forecasts relied upon by the Companies. This includes more up-to-date information provided by ICF—the Companies' consultant in this case.

Q Would updating this information change the projected value of the proposed transaction?

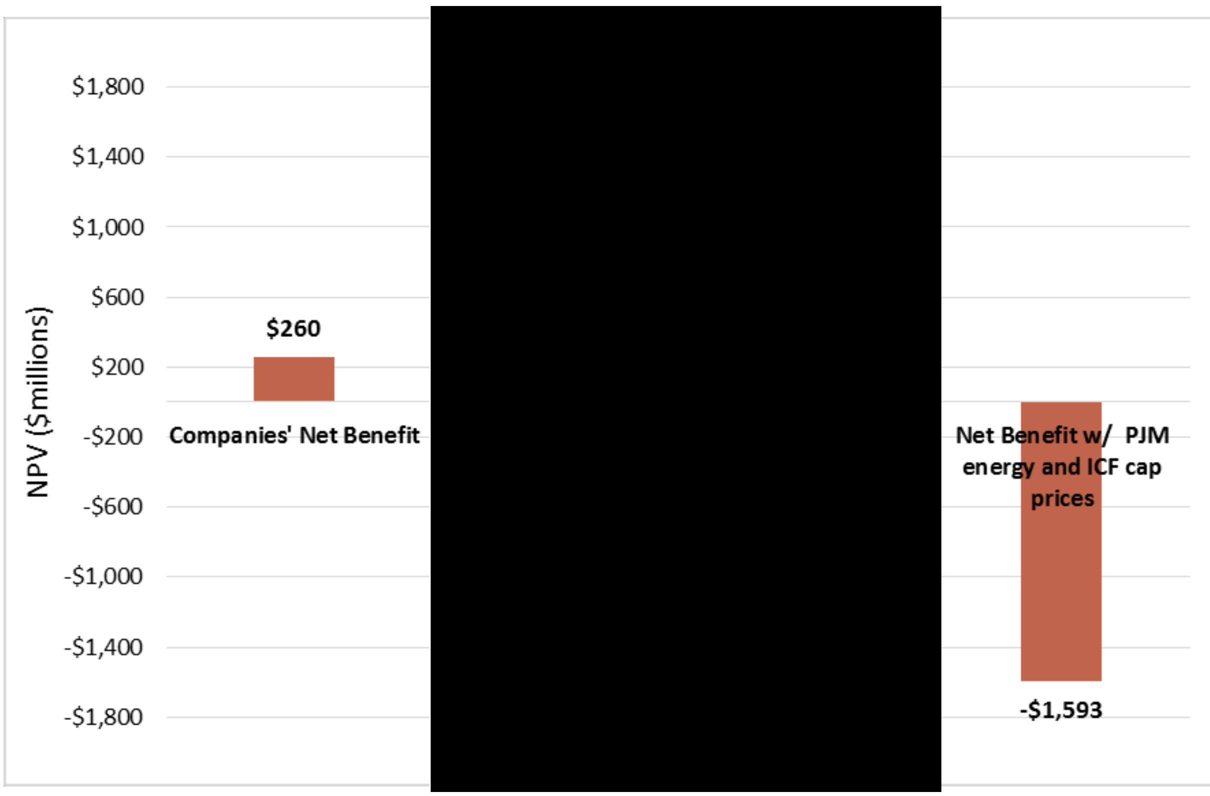
A Yes. As I will explain in further detail in my testimony, I have updated key assumptions and estimated the net benefit of the proposal under these assumptions. The summary of my findings compared to the $260 million net benefit estimated by the Companies (shown in CONFIDENTIAL Figure 2) include:

- Using ICF's more recent capacity price forecast (and the actual prices through the 2019/2020 PJM auction) reduces the projected net benefit [redacted]. Thus [redacted] of the proposal's net benefits are removed when updating capacity prices alone.[3]

[3] The estimates also include the confidential results of the transitional auctions which the Companies provided on page 83 of their Post-hearing Reply Brief. My adjusted NPV estimates incorporate these results as well as the "risk-sharing" credit (when applicable) discussed in the Modified Rider RRS proposal.

- Using a recent PJM energy price forecast instead of the Companies' stale and inflated forecast results in the proposal having a [redacted] to ratepayers. This shows that the greatest risk of the proposal is that energy prices will be lower than the two-year-old price forecast that the Companies continue to rely on. Given recent data and more up-to-date forecasts, it is likely that this risk will cost ratepayers substantially.

- Combining the more recent capacity and energy price forecasts leads to an almost $1.6 billion cost to ratepayers.



CONFIDENTIAL Figure 2: Net Benefits (Costs) of the Proposal (NPV, millions)

A. UPDATED ENERGY PRICE EXPECTATIONS SHOW THAT RATEPAYERS LOSE SUBSTANTIALLY

Q Are natural gas prices an important determinant of the value of the transaction?

A Yes. Natural gas prices are highly correlated with energy prices and, therefore, will play an important role in how much revenue the ratepayers would collect under Modified Rider RRS. The ICF natural gas price forecast used by the Companies is outdated and unreasonably high which, in turn, contributes to ICF projecting energy prices that are too high, as I will discuss later.

Q How have natural gas prices changed since the Companies' valuation of the proposed transaction?

A The average natural gas price was $2.63 per MMBtu in 2015 and $1.97 per MMBtu in 2016 (January through May). The ICF forecast used in the filing predicted prices that are more than double the year-to-date price through May 2016 and almost [redacted] than the expected prices in 2017 (see CONFIDENTIAL Table 1). Futures contracts for natural gas show that the market expects prices to remain around $3 per MMBtu through 2018, while the projection from mid-2014 that the Companies rely on has prices [redacted] by 2018.

CONFIDENTIAL Table 1: ICF Henry Hub Forecast Compared to 2015 and 2016 Actual Prices and 2017 and 2018 NYMEX Futures ($/MMBtu)[4]

	ICF forecast (used in filing)	Actual (2015-May 2016) and NYMEX (2017-2018)	ICF [redacted] (%)
2015	$4.34	$2.63	65%
2016	$4.28	$1.97	117%
[redacted]	[redacted]	$3.07	[redacted]
[redacted]	[redacted]	$3.00	[redacted]

Q Has ICF produced a more recent forecast that more accurately reflects natural gas price expectations?

A Yes. They have produced several publicly available forecasts since the filing—all of which are [redacted] than the 2014 forecast that the Companies continue to rely on this proceeding. These forecasts provide further evidence that the mid-2014 ICF forecast is outdated and should not be relied on in evaluating the Modified Rider RRS in June 2016. These more up-to-date ICF forecasts (shown in CONFIDENTIAL Figure 3) include:

- An **August 2015** forecast provided to DTE Electric in Michigan.[5] As shown below, this forecast is [redacted] in every year than the ICF forecast used in the Companies' filing.
- A **Fall 2015** forecast used in Dominion Power's 2016 Integrated Resource Plan which lowered expected prices in 2016 and 2017--relative to the

[4] Natural gas prices in 2015 and 2016 are annual averages of Henry Hub monthly prices from January 2015 through May 2016 reported by EIA (available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm). NYMEX futures are from June 14, 2016 (downloaded from: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html). ICF forecast prices are reported in the workpapers of Judah Rose.

[5] Exhibit A-25, Before the Michigan PSC, Case No.: U-17920, p.17, attached as Exhibit TFC-44 to my Third Supplemental Testimony. SC Ex. 95. Numbers adjusted to nominal dollars based on 2.1% annual inflation. This forecast assumed Clean Power Plan (CPP) compliance.

August 2015 forecast.[6] As shown below, this forecast is [redacted] than the ICF forecast used in the Companies' filing for every year through 2024.

- A **March 2016** forecast showed similar prices in 2016 and 2017 to the Fall 2015 forecast and lower prices through 2021.[7] As shown below, this forecast is [redacted] than the ICF forecast used in the Companies' filing.

[redacted]

CONFIDENTIAL Figure 3: Comparison of Henry Hub Natural Gas Price Forecasts ($/MMBtu)[8]

[6] Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan (Dominion IRP), Before the Virginia State Corporation Commission and North Carolina Utilities Commission, April 29, 2016. Attached as Exhibit TFC-46. This refers to the ICF Reference Case. ICF conducted several scenarios in this IRP—including a CPP case which had lower prices than the Reference Case. The Reference Case methodology was similar to that used by Mr. Rose in the Companies' filing regarding carbon regulation. Available at: https://www.dom.com/library/domcom/pdfs/electric-generation/2016-irp.pdf?la=en

[7] ICF, Future of Fuel: Opportunities in an Evolving Global Market, March 25, 2016. Available at: http://www.icfi.com/insights/white-papers/2016/the-future-of-fuel. Attached as Exhibit TFC-47.

[8] *Supra* notes 5 through 7.

Q How much [redacted] is the ICF forecast used in the Companies' filing compared to its more recent forecasts?

A The mid-2014 ICF forecast being relied upon in this filing predicts prices that are 71 percent higher than its March 2016 forecast of 2016 prices. Substituting in a more up-to-date and reasonable forecast would have a substantially negative impact on the proposed transaction. As I will show, such a substitution would actually lead to a substantial cost to ratepayers.

CONFIDENTIAL Table 2: ICF Henry Hub Natural Gas Price Forecast Used in Filing Compared to ICF March 2016 Forecast ($/MMBtu)[9]

	ICF forecast (used in filing)	ICF March 2016	ICF 2014 forecast [redacted] (%)
2016	$4.28	$2.50	71%
2017	[redacted]	$2.87	[redacted]
2018	[redacted]	$2.98	[redacted]
2019	[redacted]	$3.86	[redacted]
2020	[redacted]	$4.67	[redacted]
2021	[redacted]	$5.06	[redacted]

Q Have other entities produced price forecasts that are similar to ICF's more recent work?

A Yes. At least two other sources forecast prices that are similar to ICF's most recent forecasts. These are overlaid on the ICF forecasts in CONFIDENTIAL Figure 4, including: 1) a recent forecast from PJM and 2) the most recent forecast from the Energy Information Administration (EIA) in its 2016 Annual Energy Outlook (AEO) Early Release.[10] Compared to its 2015 projection, the EIA now projects lower prices throughout including "stable prices" in the long–term due to

[9] *Supra* note 5.
[10] PJM Transmission Expansion Advisory Committee (TEAC) Market Efficiency Update, June 9, 2016. Available at: http://www.pjm.com/committees-and-groups/committees/teac.aspx; EIA AEO 2016 Early Release. Available at: http://www.eia.gov/forecasts/aeo/data/browser/#/?id=13-AEO2016&cases=ref2016~ref_no_cpp&sourcekey=0.

"technology improvements, which result in drilling cost declines and increased recovery rates, allow productive capacity to keep pace with demand."[11] As with the more recent ICF work, the EIA and PJM both expect natural gas prices to be [redacted] than what is being used in the Companies' filing.

[redacted]

CONFIDENTIAL Figure 4: Comparison of Natural Gas Price Forecasts ($/MMBtu)[12]

Q Have the 2014 ICF forecasts also overestimated actual energy prices?

A Yes. The mid-2014 ICF energy prices forecast relied on in for the proposal in the Companies' rehearing application also suffers from being out of date and [redacted] biased. This effect is seen when comparing ICF's energy prices to

[11] EIA. Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases. Available at: https://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf. Attached as Exhibit TFC-48.
[12] *Id.*; *supra* notes 5 through 8.

actual prices. As shown in CONFIDENTIAL Figure 5, from January 2015 through May 2016, ICF has [redacted] the energy price in every month but one. For 2015, ICF's 2014 forecast predicted prices that were [redacted] than actual AEP-Dayton prices. That old forecast's performance has only [redacted] since then. So far in 2016, ICF's predictions are [redacted] than actual prices. This result is a reflection of using stale forecasts that have not been updated to reflect changes in natural gas prices and load growth, among other key factors used in developing energy prices. If Rider RRS (either the original or modified version) had been in effect in 2015 or in the beginning of this year, ratepayers would have [redacted] than what the Companies had projected for those periods.

[redacted]

CONFIDENTIAL Figure 5: Comparison of Energy Price Forecasts ($/MWh, all-hours price)[13]

Q Are there more recent energy price forecasts that are publicly available?

A Yes. In conducting an analysis of the Clean Power Plan (CPP), PJM released a region-wide energy price forecast. This energy forecast relates to the PJM natural gas price forecast I discussed previously (see CONFIDENTIAL Figure 4), which was similar to more recent ICF natural gas price forecasts and [redacted] than the one relied upon in this filing. The PJM forecast of energy prices is shown below in Table 3.

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[13] ICF forecast from Data Response to SC Set 1-RPD-28, Attachment 1 – Confidential, AEP Dayton Hub prices; Actual prices from PJM Day-ahead LMP's for AEP Dayton Hub, available at: http://www.pjm.com/markets-and-operations/energy/day-ahead/lmpda.aspx. These are in nominal dollars.

Table 3: PJM Energy Price Forecast ($/MWh, load-weighted)[14]

	2018	2019	2020	2021	2022	2023	2024
PJM forecast	$32	$37	$40	$43	$46	$49	$50

Q Is this energy price forecast likely inflated relative to what will be used in the proposal?

A Yes. The proposal will credit energy revenue using actual AEP-Dayton Hub prices.[15] The average energy revenue per MWh projected by the Companies is close to their projections of the all-hours energy price. As shown in Table 4, the load-weighted AEP-Dayton price is typically lower than the equivalent for PJM as a whole. These load-weighted prices are higher than the all-hours prices because the former adjusts for the fact that prices are higher in hours where load is higher. Thus the PJM-wide, load-weighted energy price is likely higher than the actual energy prices that will be applied to the proposal.

[14] PJM Clean Power Plan Modeling: Preliminary Phase 1 Long-Term Economic Compliance Analysis Results, May 6, 2016. These are in nominal dollars. The scenario shown here is "Trade-Ready Mass" for CPP compliance (i.e. mass-based compliance with state trading); however, these prices are nearly identical to PJM's "Reference" (i.e. no CPP) and "State Mass" (i.e. mass-based state compliance) cases through 2024. Available at: http://www.pjm.com/~/media/documents/reports/20160506-pjm-clean-power-plan.ashx. Attached as Exhibit TFC-49.

[15] Mikkelsen Rehearing Testimony, p.7, line 21.

Table 4: PJM Energy Prices ($/MWh, load-weighted)[16]

	LMP ($/MWh)		Percent of PJM-wide load-weighted price	
	2014	2015	2014	2015
PJM, Load-weighted	$53.62	$36.73		
AEP-Dayton, Load-weighted	$46.64	$32.77	87%	89%
AEP-Dayton, All-hours average	$44.08	$31.48	82%	86%

Q How does the value of the transaction change with the PJM energy price forecast?

A The value of the proxy transaction is highly sensitive to energy prices, which means that ratepayers would still be subject to the substantial risk under Modified Rider RRS that energy prices will continue to be [redacted] than the mid-2014 forecast the Companies relied on. Using the PJM energy price forecast results in a [redacted] (compared to the Companies' estimate of a $260 million benefit). Shown in CONFIDENTIAL Figure 6, I have substituted the PJM load-weighted price for the Companies' projections of average prices per MWh. This substitution shows the substantial costs that ratepayers will face if, as PJM forecasts, energy prices are [redacted] than what the Companies assumed two years ago. Also note that the PJM forecast begins in 2018. In performing this analysis, I have not adjusted the 2016 and 2017 energy prices relied on by the Companies to reflect more up-to-date forecasts for those time periods. If I did so, then my results would show [redacted] for ratepayers.

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16. Monitoring Analytics, LLC, State of the Market Report for PJM 2015 (Table 11-6), March 10, 2016. Both available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml

[redacted]

CONFIDENTIAL Figure 6: Net Benefits (Costs) of the Proposal Using PJM Energy Price Forecasts (NPV, millions)

Q Could ratepayers still lose if actual energy prices increase from their current levels during the proposal's term?

A Yes. Energy prices still increase from their current levels under the PJM forecast. As such, Ms. Mikkelsen is not correct when she says that "if power prices rise" from their "current low levels . . . customers will begin to see credits."[17] Instead, ratepayers will only begin to see credits under the Modified Rider RRS if energy prices (and capacity prices) rise from their current lows to levels that are close to what ICF forecasted back in 2014. Given how [redacted] [redacted] actual energy prices (and capacity prices) have been compared to ICF's forecast to date, and how inflated the ICF forecasts are to begin with, while energy prices may increase from their current levels, it is highly unlikely that they will reach the heights set

[17] Mikkelsen Rehearing Testimony at 10.

forth in ICF's 2014 forecast. And under Modified Rider RRS, it is ratepayers that bear the risk around such energy prices.

B. UPDATED CAPACITY PRICE EXPECTATIONS ALONE WOULD REMOVE MOST OF THE PROPOSAL'S PURPORTED BENEFITS

Q Are ratepayers also subject to capacity price risk?

A Yes. Under Modified Rider RRS, ratepayers would be credited capacity revenue based on the amount of capacity that the Companies projected would clear the capacity auction multiplied by actual capacity prices, rather than the prices forecasted by the Companies. As such, even under Modified Rider RRS ratepayers would still be subject to the risk that actual capacity prices will be considerably lower than what the Companies forecast.

Q Is the capacity price forecast used by the Companies unreasonable and stale?

A Yes. The capacity revenue projection relied on by the Companies unreasonably assumes that capacity prices will [redacted]. Continuing to use this capacity price forecast overvalues the proposal. As shown below in CONFIDENTIAL Figure 7, the actual capacity auction results for the 2018/2019 delivery year were [redacted] than ICF anticipated: it projected [redacted] whereas the actual price was $165 per MW-day (such that ICF's forecast was [redacted] higher than the actual result).[18] The ICF forecast price for the 2019/2020 delivery year was [redacted] the actual result: it projected [redacted] whereas the actual price was $100 per MW-day.[19] While the Companies have provided actual capacity revenue through the 2018/2019 auction (which is included in my NPV estimates), they have not provided the 2019/2020 results nor have they updated the price assumption for that year in their valuation.

[18] PJM BRA results (available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx). The Companies' capacity price projections are presented in the workpapers for Mr. Lisowski's direct testimony. Attached as Exhibit TFC-50.
[19] *Id.*

Q Has ICF produced a more recent forecast that more accurately reflects capacity price expectations?

A Yes. ICF's Fall 2015 forecast, which was publicly disclosed in Dominion Energy's April 2016 Integrated Resource Plan, produced a capacity price forecast in addition to the aforementioned natural gas price forecast (see CONFIDENTIAL Figure 3). This more recent view from ICF (shown in CONFIDENTIAL Figure 7) shows a [redacted] in expected prices relative to what it expected in 2014. Unfortunately, the Companies continue to rely on the stale and inflated expectations from more than two years ago. They have failed to update their projections of capacity revenue from the proposal even though ICF's outlook has obviously changed. In the results presented further in my testimony, I use the actual 2019/2020 price and the ICF Fall 2015 forecast for subsequent years.

[redacted]

CONFIDENTIAL Figure 7: Companies' Projected Capacity Prices Compared to Actual Auction Results and ICF Fall 2015 Forecast ($/MW-day)[20]

Q How does the value of the transaction change with the updated ICF capacity price forecast?

A Like generation levels, capacity levels are also fixed in the Companies' new proposal while energy and capacity prices are not. As I did with energy prices, I have provided an updated estimate of the net benefit of the proposal with updated capacity prices. Once again, the Companies ignored new information to their ratepayers' detriment. Shown in CONFIDENTIAL Figure 8, using the more recent ICF forecast reduces the projected benefit of Modified Rider RRS to [redacted] (compared to the Companies' estimate of $260 million)—a [redacted] reduction in value. This shows the substantial risk that ratepayers will be

[20] *Id. Supra note 7.*This refers to the ICF Reference Case. Other scenarios in the IRP show lower capacity prices than the Reference Case shown here.

subjected to when capacity prices are [redacted] than what the Companies assumed two years ago—even without adjusting the Companies' assumed energy prices.

[redacted]

CONFIDENTIAL Figure 8: Net Benefits (Costs) of the Proposal Using ICF Fall 2015 Capacity Prices (NPV, millions)

Q Have you estimated the combined effects of using more up-to-date capacity and energy prices?

A Yes. Shown in Figure 9, using ICF's Fall 2015 capacity price forecast and the recent PJM energy price forecast leads to an almost $1.6 billion NPV cost to ratepayers. The combined effects of updating capacity and energy prices show the cost that ratepayers will likely pay based on forecasts that are more current than the stale forecasts from 2014 that the Companies are continuing to use.

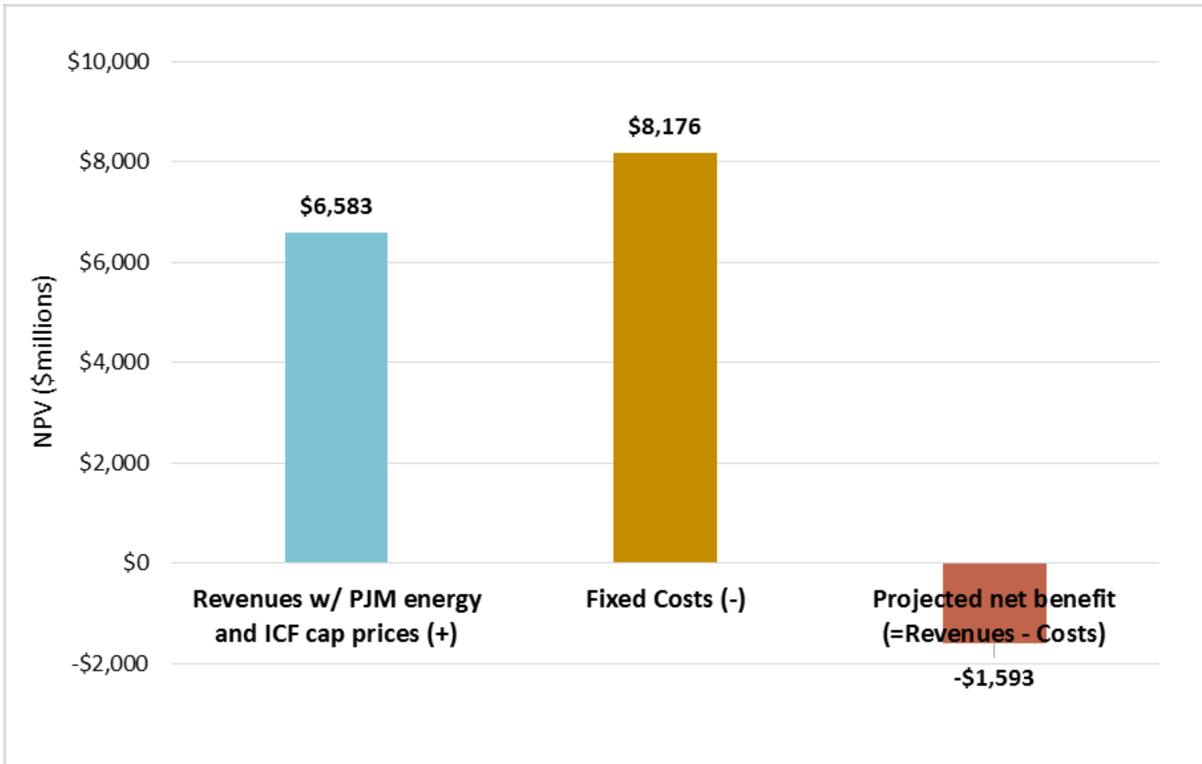

Figure 9: Net Benefits (Costs) of the Proposal Using Updated Energy and Capacity Price Forecasts (NPV, millions)

Q Given the use of outdated forecasts, should the proposal be pursued at this time?

A No. Under the Companies' proposal, $8 billion NPV in costs would be passed onto ratepayers. The proposal will only benefit ratepayers if they can more than make up for these guaranteed costs with uncertain revenues, which will vary with actual energy and capacity prices. Unfortunately, the Companies' projections of revenue credits to ratepayers are based on two-year old natural gas, energy, and capacity prices. Even though actual market conditions to date have differed widely from what ICF forecast, and the available evidence (including ICF's own updated forecasts) suggest that they will continue to do so, the Companies' projection of charges and credits under the Modified Rider RRS proposal is based on the outdated mid-2014 ICF forecasts. Such an approach is unreasonable. Moreover, under the Companies' Modified Rider RRS proposal, ratepayers would still be subject to the significant risk that energy, capacity, and natural gas prices will [redacted] be significantly lower than ICF's [redacted] forecasts from 2014. Thus, the new proposal leaves ratepayers vulnerable to these market risks and, if approved, the proposal will likely cost them substantially.

IV. FINDINGS AND RECOMMENDATIONS

Q What are your findings?

A My key findings are the following:

1. This proposal is risky and will likely lead to higher costs for Ohio ratepayers. While the costs of the proposal are now fixed for the eight-year term, the revenues generated will vary with actual energy and capacity prices. If the uncertain revenue does not outweigh the guaranteed costs, then ratepayers lose. This scenario is highly likely given that the Companies' two-year old energy and capacity price expectations are unreasonably high when compared to more recent price forecasts—including those from the Companies' own consultant.

2. The Companies' natural gas price forecast is stale and inflated. The ICF forecast used in the filing predicted prices that are more than double the prices so far in 2016 (see CONFIDENTIAL Table 1). Since the filing, ICF has developed lower natural gas price forecasts. Yet, the Companies have failed to use this information. This omission significantly inflates the value of the proposal.

3. Because energy prices are highly correlated with natural gas prices, the former are also stale and inflated. Using a recent PJM energy price forecast results in a [redacted] (compared to the Companies' estimate of a $260 million benefit). This shows the substantial risk that

ratepayers will be subjected to if, as PJM has recently forecast, energy prices are [redacted] than what the Companies assumed two years ago.

4. The capacity prices assumed in the filing are also stale and inflated. Using actual prices through the 2019/2020 delivery and the more recent ICF forecast for the later years reduces the projected benefit by [redacted], to [redacted] (compared to the Companies' estimate of $260 million). This shows the substantial risk that ratepayers will be subjected to if, as ICF forecast in fall of 2015, capacity prices are [redacted] than what the Companies assumed two years ago.

5. Combining the effects of up-to-date capacity and energy price forecasts leads to an almost $1.6 billion NPV cost to ratepayers. The potential costs of the proposal are too large for the Companies to continually fail to update key assumptions.

Q **What are your recommendations?**

A For reasons discussed above, I recommend that the modified Rider RRS proposal be denied.

Q **Does this conclude your testimony?**

A Yes, it does. However, I reserve the right to update or supplement my testimony based on new information that may become available.

CERTIFICATE OF SERVICE

I hereby certify that on this date a copy of the foregoing Redacted Version of the Rehearing Testimony of Tyler Comings was served upon the following parties via electronic mail.

Date: June 22, 2016

s/ Michael Soules
Michael Soules

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Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

PUBLIC VERSION

Case No. PUE-2016-00049
Docket No. E-100, Sub 147

Filed: April 29, 2016

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LIST OF ACRONYMS

Acronym	Meaning
2015 Plan	2015 Integrated Resource Plan
2016 Plan	2016 Integrated Resource Plan
AC	Alternating Current
ACP	Atlantic Coast Pipeline
AMI	Advanced Metering Infrastructure
BTMG	Behind-the-Meter Generation
Btu	British Thermal Unit
CAPP	Central Appalachian
CC	Combined-Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CEIP	Clean Energy Incentive Program
CFB	Circulating Fluidized Bed
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction Permit and Operating License
Company	Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan, Rule 111(d)
CSAPR	Cross-State Air Pollution Rule
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
DC	Direct Current
DEQ	Virginia Department of Environmental Quality
DG	Distributed Generation
DOE	U.S. Department of Energy
DOM LSE	Dominion Load Serving Entity
DOM Zone	Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSM	Demand-Side Management
EGU	Electric Generating Units
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ERC	Emission Rate Credit
ESBWR	Economic Simplified Boiling Water Reactor
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GEH	GE-Hitachi Nuclear Energy Americas LLC
GHG	Greenhouse Gas
GSP	Gross State Product
GWh	Gigawatt Hour(s)
Hg	Mercury
HVAC	Heating, Ventilating, and Air Conditioning
ICF	ICF International, Inc.
IDR	Interval Data Recorder
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated-Gasification Combined-Cycle
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt Hour(s)
LMP	Locational Marginal Pricing
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
LTC	Load Tap Changer

Acronym	Meaning
MATS	Mercury and Air Toxics Standards
MMBTU	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt(s)
MWh	Megawatt Hour(s)
MVA	Mega Volt Ampere
NAAQS	National Ambient Air Quality Standards
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NUG	Non-Utility Generation or Non-Utility Generator
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturers
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection, L.L.C.
Plan	2016 Integrated Resource Plan
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RAC	Rate Adjustment Clause
RACT	Reasonable Available Control Technology
REC	Renewable Energy Certificate
REPS	Renewable Energy and Energy Efficiency Portfolio Standard (NC)
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RPM	Reliability Pricing Model
RPS	Renewable Energy Portfolio Standard (VA)
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SG	Standby Generation
SIP	State Implementation Plan
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SPP	Solar Partnership Program
SRP	Stakeholder Review Process
STAP	Short-Term Action Plan
Strategist	Strategist Model
T&D	Transmission and Distribution
TOU	Time-of-Use Rate
TRC	Total Resource Cost
UCT	Utility Cost Test
Va. Code	Code of Virginia
VCHEC	Virginia City Hybrid Energy Center
VOW	Virginia Offshore Wind Coalition
VOWDA	Virginia Offshore Wind Development Authority
VOWTAP	Virginia Offshore Wind Technology Advancement Project
WACC	Weighted Average Cost of Capital
WEA	Wind Energy Area
WTI	West Texas Intermediate

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTEGRATED RESOURCE PLAN OVERVIEW

Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (collectively, the "Company") hereby files its 2016 Integrated Resource Plan ("2016 Plan" or "Plan") with the Virginia State Corporation Commission ("SCC") in accordance with § 56-599 of the Code of Virginia (or "Va. Code"), as amended by Senate Bill 1349 ("SB 1349") effective July 1, 2015 (Chapter 6 of the 2015 Virginia Acts of Assembly), and the SCC's guidelines issued on December 23, 2008. The Plan is also filed with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of NCUC's Rules and Regulations.

The 2016 Plan was prepared for the Dominion Load Serving Entity ("DOM LSE"), and represents the Company's service territories in the Commonwealth of Virginia and the State of North Carolina, which are part of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO"). Subject to provisions of Virginia and North Carolina law, the Company prepares an integrated resource plan for filing in each jurisdiction every year. Last year, the Company filed its 2015 Integrated Resource Plan ("2015 Plan") with the SCC (Case No. PUE-2015-00035) and as an update with the NCUC (Docket No. E-100, Sub 141). On December 30, 2015, the SCC issued its Final Order finding the 2015 Plan ("2015 Plan Final Order") in the public interest and reasonable for filing as a planning document, and requiring additional analyses in several areas be included in future integrated resource plan filings. On March 22, 2016, the NCUC issued an order accepting the Company's update filing as complete and fulfilling the requirements set out in NCUC Rule R8-60.

As with each Plan filing, the Company is committed in this 2016 Plan to addressing concerns and/or requirements identified by the SCC or NCUC in prior relevant orders, as well as new or proposed provisions of state and federal law. Notably, for purposes herein, this document includes the greenhouse gas ("GHG") regulations promulgated by the U.S. Environmental Protection Agency ("EPA") on August 3, 2015. These final EPA GHG regulations, known as the Clean Power Plan ("CPP") or 111(d) Rule, provide states with several options for restricting carbon dioxide ("CO_2") emissions, either through tonnage caps on the total amount of carbon generated by electric generating units ("EGUs"), or through rate-based restrictions on the average amount of CO_2 emitted per unit of electricity generated for all EGUs or for specific classes of EGUs, which is an approach generally referred to as carbon intensity regulation.

The CPP, and the Company's evaluation of compliance with these emission levels, as they existed before the CPP was stayed by the February 9, 2016 Order ("Stay Order") of the Supreme Court of the United States ("Supreme Court"), is presented herein. The Supreme Court's Stay Order has the effect of suspending the implementation and enforcement of the CPP pending judicial review by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") and possibly the Supreme Court. However, as discussed further below, the Company has elected to continue to evaluate CPP compliance. Even with the exact future of the CPP undetermined at present, the Company believes that future regulation will require it to address carbon and carbon emissions in some form beyond what is required today. Therefore, it is critical at this time that the Company preserves all options available that will ensure the Company, its customers, and the Commonwealth of Virginia can efficiently transition to a low carbon future while maintaining reliability. This includes the continued reasonable development efforts associated with traditional and new low- or zero-emitting supply side resources such as new nuclear (North Anna 3), onshore wind, offshore wind, and solar along with cost-effective demand-side resources. Many of these resources are included in the alternative plans examined in this 2016 Plan. Some of these resources, however, have not been included given the time period examined and other constraints incorporated into this 2016 Plan. This is not to say that these resources will not be needed in the future. In fact the Company maintains that it is highly likely that resources such as North Anna 3, wind generation, and new demand-side resources will be needed at some point in the future beyond that studied in this 2016 Plan, or sooner should fuel prices increase (especially natural gas prices). Throughout this document, the Company has made it a point to identify areas of future uncertainty including uncertainty associated with future carbon emissions regulation. One must ask, will the CPP remain in its current form or will it be revised? Also, should the CPP remain intact as promulgated, what happens beyond the 2030 final target date? When considering questions such as these, it is reasonable to anticipate that resources such as North Anna 3, offshore wind, and new demand-side resources may be required in the future in order to provide reliable electric service to the Company's customers. A reasonable albeit simplified conclusion is "not if but when" will these resources be needed. As mentioned above, in this 2016 Plan some of these resources are not included but those same resources may be reasonable choices in future Plans. Continuing the significant progress is particularly important with extremely long lead time generation projects like North Anna 3 and off-shore wind. Therefore, once again, it is imperative that the Company preserve its supply- and demand-side options for the future.

Additionally, low natural gas prices along with societal pressures and/or regulatory constraints have adversely impacted the U.S. coal generation fleet which has resulted in an extraordinarily high level of coal unit retirements over the last five to ten years. Certainly several of the Company's own coal-fired units have not escaped this fate. With these pressures in mind it is important to understand that the Company's coal generation fleet has been the backbone of its generation portfolio and have reliably served the Company's customers for many years. Simultaneously, these facilities have also added a key element of diversity to the Company's overall fleet which has helped keep rates stable in the Commonwealth of Virginia and North Carolina. As Virginia and the nation transitions to a low carbon future this element of diversity must not be lost. The Company's goal is to find ways to efficiently add to its generation fleet diversity while maintaining its coal fleet. The Company asserts that this strategy will, in the long term, provide superior benefit to our customers similar to the value such diversity has provided those same customers in the past.

Incorporated in this 2016 Plan are provisions of SB 1349, which amend Va. Code § 56-599, including requiring annual integrated resource plans from investor-owned utilities by May 1 of each year starting in 2016, and establishing a "Transitional Rate Period" consisting of five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. During the Transitional Rate Period, SB 1349 directs the SCC to submit a report and make recommendations to the Governor and the Virginia General Assembly by December 1 of each year, which assesses the updated integrated resource plan of any investor-owned incumbent electric utility, including an analysis of the amount, reliability and type of generation facilities needed to serve Virginia native load compared to what is then available to serve such load and what may be available in the future in view of market conditions and current and pending state and federal environmental regulations. The reports must also estimate impacts in Virginia on electric rates based on implementation of the CPP. This is the Company's second integrated resource plan submitted during the Transitional Rate Period. The information and analysis presented herein are intended to inform the reporting requirements for the SCC, as well as reflect the period of uncertainty continuing to face the Company during the Transitional Rate Period, as recognized by the Governor and the Virginia General Assembly through passage of SB 1349.

As with prior filings, the Company's objective was to identify the mix of resources necessary to meet its customers' projected energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost, while considering future uncertainties. The Company's options for meeting these future needs are: i) supply-side resources, ii) demand-side resources, and iii) market purchases. A balanced approach, which includes consideration of options for maintaining and enhancing rate stability, energy independence and economic development, as well as input from stakeholders, will help the Company meet growing demand, while protecting customers from a variety of potentially negative impacts and challenges. These include changing regulatory requirements, particularly the EPA's regulation of CO_2 emissions from new and existing electric generation, as well as commodity price volatility and reliability concerns based on overreliance on any single fuel source.

The Company primarily used the Strategist model ("Strategist"), a utility modeling and resource optimization tool, to develop this 2016 Plan over a 25-year period, beginning in 2017 and continuing through 2041 ("Study Period"), using 2016 as the base year. Unless otherwise specified, text, numbers, and appendices are displayed for a 15-year period from 2017 to 2031 ("Planning Period") for Plan B: Intensity-Based Dual Rate. This 2016 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, economic conditions, environmental regulations, construction and equipment costs, Demand-Side Management ("DSM") programs, and many other regulatory and market developments that may occur during the Study Period.

Included in this 2016 Plan are sections on load forecasting and alternative rate studies (Chapter 2), existing resources and resources currently under development (Chapter 3), planning assumptions (Chapter 4), and future resources (Chapter 5). Additionally, there is a section describing the development of the Plan (Chapter 6), which defines the integrated resource planning ("IRP") process, and outlines alternative plans that were compared by weighing the costs of those plans using a variety of scenarios and other non-cost factors, and also further compared by using a comprehensive risk analysis; and a Portfolio Evaluation Scorecard (or "Scorecard") process. This analysis allowed the Company to examine alternative plans given significant industry uncertainties, such as environmental regulations, commodity and construction prices, and resource mix. The Scorecard provides a quantitative and qualitative measurement system to assess the different alternatives, using criteria that include cost, rate stability, and benefits and risks. Finally, a Short-Term Action Plan (or "STAP") (Chapter 7) is included, which discusses the Company's specific actions currently underway to support the 2016 Plan over the next five years (2017 - 2021). The STAP represents the short-term path forward that the Company maintains will best meet the energy and capacity needs of its customers at the lowest reasonable cost over the next five years, with due quantification, consideration and analysis of future risks and uncertainties facing the industry, the Company, and its customers.

As noted above, the Company's balanced approach to developing its Plan also includes input from stakeholders. Starting in 2010, the Company initiated its Stakeholder Review Process ("SRP") in Virginia, which is a forum to inform stakeholders from across its service territory about the IRP process, and to provide more specific information about the Company's planning process, including IRP and DSM initiatives, and to receive stakeholder input. The Company coordinates with interested parties in sharing DSM program Evaluation, Measurement and Verification ("EM&V") results and in developing future DSM program proposals, pursuant to an SCC directive. The Company is committed to continuing the SRP and expects the next SRP meeting involving stakeholders across its service territory to be after the filing of this 2016 Plan.

Finally, the Company notes that inclusion of a project or resource in any given year's integrated resource plan is not a commitment to construct or implement a particular project or a request for approval of a particular project. Conversely, not including a specific project in a given year's plan does not preclude the Company from including that project in subsequent regulatory filings. Rather, an integrated resource plan is a long-term planning document based on current market information and projections and should be viewed in that context.

1.2 COMPANY DESCRIPTION

The Company, headquartered in Richmond, Virginia, currently serves approximately 2.5 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company's supply-side portfolio consists of 21,107 megawatts ("MW") of generation capacity, including approximately 1,277 MW of fossil-burning and renewable non-utility generation ("NUG") resources, over 6,500 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and more than 57,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia, North Carolina and West Virginia. The Company is a member of PJM, the operator of the wholesale electric grid in the Mid-Atlantic region of the United States.

The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, biomass and solar facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

1.3 2016 INTEGRATED RESOURCE PLANNING PROCESS

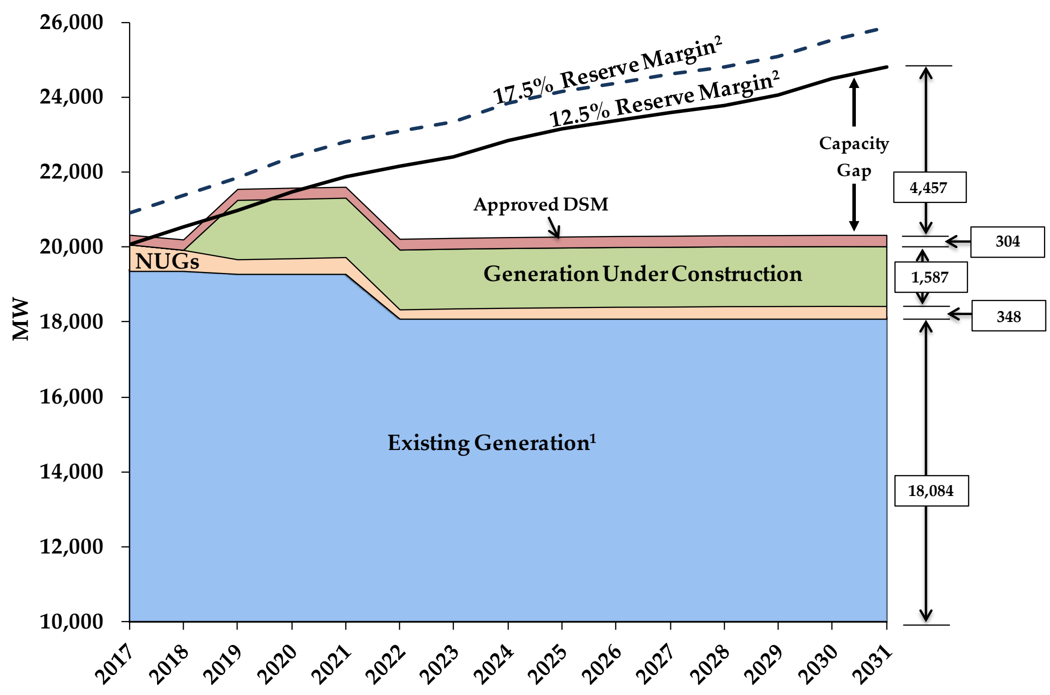
In order to meet future customer needs at the lowest reasonable cost while maintaining reliability and flexibility, the Company must take into consideration the uncertainties and risks associated with the energy industry. Uncertainties assessed in this 2016 Plan include:

- load growth in the Company's service territory;
- effective and anticipated EPA regulations concerning air, water, and solid waste constituents (as shown in Figure 3.1.3.3), particularly including the EPA GHG regulations (i.e., the CPP) regarding CO_2 emissions from electric generating units;
- fuel prices;

- cost and performance of energy technologies;
- renewable energy requirements including integration of intermittent renewable generation;
- current and future DSM;
- retirement of non-Company controlled units that may impact available purchased power volumes; and
- retirement of Company-owned generation units.

The Company developed this integrated resource plan based on its evaluation of various supply- and demand-side alternatives and in consideration of acceptable levels of risk that maintain the option to develop a diverse mix of resources for the benefit of its customers. Various planning groups throughout the Company provided input and insight into evaluating all viable options, including existing generation, DSM programs, and new (both traditional and alternative) resources to meet the growing demand in the Company's service territory. The IRP process began with the development of the Company's long-term load forecast, which indicates that over the Planning Period (2017 – 2031), the DOM LSE is expected to have annual increases in future peak and energy requirements of 1.5% and 1.5%, respectively. Collectively, these elements assisted in determining updated capacity and energy requirements as illustrated in Figure 1.3.1 and Figure 1.3.2.

Figure 1.3.1 - Current Company Capacity Position (2017 – 2031)

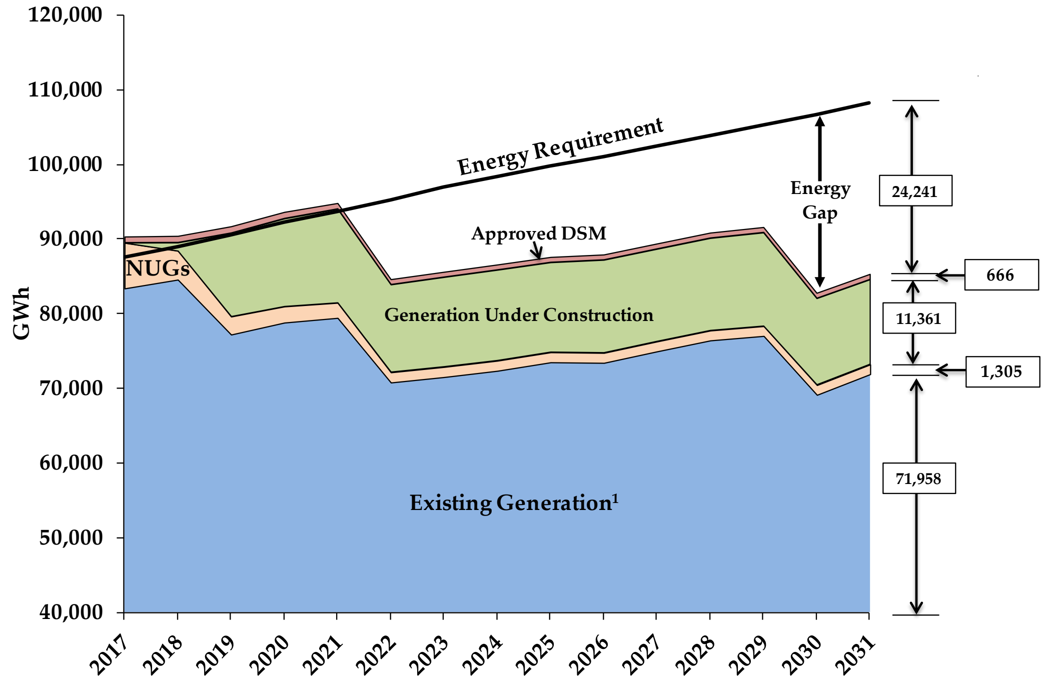


Note: The values in the boxes represent total capacity in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

2) See Section 4.2.2.

Figure 1.3.2 - Current Company Energy Position (2017 – 2031)



Note: The values in the boxes represent total energy in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

1.3.1 EPA's CLEAN POWER PLAN

The importance of lower carbon emitting generation was reinforced on August 3, 2015, with the EPA's issuance of its final EPA GHG regulations. These regulations, known as the Clean Power Plan (also referred to as CPP or 111(d) Rule), would significantly reduce carbon emissions from electric generating units by mandating reductions in carbon emissions. The EPA's CPP offers each state two sets of options to achieve compliance, and a federal implementation plan ("FIP" or "Federal Plan") associated with each set. These options include Rate-Based programs designed to reduce the overall CO_2 intensity (i.e., the rate of CO_2 emissions as determined by dividing the pounds of CO_2 emitted by each megawatt-hour ("MWh") of electricity produced), which are referred to hereinafter as Intensity-Based programs, and Mass-Based programs designed to reduce total CO_2 emission based on tonnage.[1] Under the CPP, each state is required to submit a state implementation plan ("SIP" or "State Plan") to the EPA detailing how it will meet its individual state targets no later than September 6, 2018. It is the Company's understanding that the Commonwealth of Virginia had intended to finalize its State Plan in the fall of 2017, a year sooner than the final submission deadline. As of this writing, both North Carolina and West Virginia have halted all state CPP compliance work pending the resolution of the Supreme Court stay. Further, both North Carolina and West Virginia are challenging the CPP in court.

[1] Although the CPP's enforceability and legal effectiveness have been stayed by the Supreme Court, for purposes of this 2016 Plan, the Company will discuss the provisions of the CPP as if the rules are enforceable and in effect both from a substantive and implementation timeframe standpoint.

Based on the Company's review of the CPP, for each of the two options (i.e., Intensity-Based and Mass-Based) for compliance, there are three sub-options, for making a total of six possible options for state compliance. They are as follows:

Intensity-Based Programs

1) Intensity-Based Dual Rate Program – An Intensity-Based CO_2 program that requires each existing: (a) fossil fuel-fired electric steam generating unit to achieve an intensity target of 1,305 lbs of CO_2 per MWh by 2030 and beyond; and (b) natural gas combined-cycle ("NGCC") unit to achieve an intensity target of 771 lbs of CO_2 per MWh by 2030, and beyond. These standards, which are based on national CO_2 performance rates, are consistent for any state that opts for this program.
2) Intensity-Based State Average Program – An Intensity-Based CO_2 program that requires all existing fossil fuel-fired generation units in the state to collectively achieve a portfolio average intensity target by 2030, and beyond. In Virginia, that average intensity is 934 lbs of CO_2 per MWh by 2030, and beyond. The 2030 and beyond targets for West Virginia and North Carolina are 1,305 lbs of CO_2 per MWh and 1,136 lbs of CO_2 per MWh, respectively.
3) A Unique State Intensity-Based Program - A unique state Intensity-Based program designed so that the ultimate state level intensity target does not exceed those targets described in the two Intensity-Based programs set forth above.

Mass-Based Programs

4) Mass-Based Emissions Cap (existing units only) Program – A Mass-Based program that limits the total CO_2 emissions from a state's existing fleet of fossil fuel-fired generating units. In Virginia, this limit is 27,433,111 short tons CO_2 in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,325,342 short tons of CO_2 and 51,266,234 short tons of CO_2, respectively.
5) Mass-Based Emissions Cap (existing and new units) Program – A Mass-Based program that limits the total CO_2 emissions from both the existing fleet of fossil-fuel fired generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of CO_2 by 2030. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,857,307 short tons of CO_2 and 51,876,856 short tons of CO_2, respectively.
6) Unique State Mass-Based Program - A unique state Mass-Based approach limiting total CO_2 emissions.

The Company anticipates that the Unique State Intensity-Based and Mass-Based Programs identified above (sub-options 3 and 6) are unlikely choices for the states in which the Company's generation fleet is located in part because of the time constraints for states to implement programs, and because of the restrictions that a unique state program would impose on operating flexibility and compliance coordination among states. Therefore, the 2016 Plan assesses the remaining four programs that are likely to be implemented in Virginia, West Virginia, and North Carolina. Per the CPP, compliance for each of the four programs begins in 2022, and includes interim CO_2 targets that must be achieved prior to the final targets in 2030 and beyond specified above. Figures 1.3.1.1 through 1.3.1.3 identify these interim targets per program per state. Also, each of the four programs has different compliance requirements that will be described in more detail in Chapters 3 and 6.

Figure 1.3.1.1 – CPP Implementation Options – Virginia

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			1,477	27,365,439	
Interim Step 1 Period 2022 - 2024	1,671	877	1,120	31,290,209	31,474,885
Interim Step 2 Period 2025 - 2027	1,500	817	1,026	28,990,999	29,614,008
Interim Step 3 Period 2028 - 2029	1,380	784	966	27,898,475	28,487,101
Final Goal 2030 and Beyond	1,305	771	934	27,433,111	27,830,174

Figure 1.3.1.2 – CPP Implementation Options – West Virginia

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			2,064	72,318,917	
Interim Step 1 Period 2022 - 2024	1,671	877	1,671	62,557,024	62,804,443
Interim Step 2 Period 2025 - 2027	1,500	817	1,500	56,762,771	57,597,448
Interim Step 3 Period 2028 - 2029	1,380	784	1,380	53,352,666	54,141,279
Final Goal 2030 and Beyond	1,305	771	1,305	51,325,342	51,857,307

Figure 1.3.1.3 – CPP Implementation Options – North Carolina

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			1,790	58,566,353	
Interim Step 1 Period 2022 - 2024	1,671	877	1,419	60,975,831	61,259,834
Interim Step 2 Period 2025 - 2027	1,500	817	1,283	55,749,239	56,707,332
Interim Step 3 Period 2028 - 2029	1,380	784	1,191	52,856,495	53,761,714
Final Goal 2030 and Beyond	1,305	771	1,136	51,266,234	51,876,856

As mentioned above, on February 9, 2016, the Supreme Court voted 5-4 to issue an order staying implementation of the CPP pending judicial review of the rule by the D.C. Circuit Court of Appeals and any subsequent review by the Supreme Court (i.e., the Stay Order). Oral arguments are scheduled before the D.C. Circuit Court on June 2, 2016. The Company believes the earliest the appeal process will be resolved is the fall of 2017.

At this time, the EPA has not indicated whether and, if so, to what extent the stay will affect the CPP compliance timeline. While it is anticipated that the deadline for states to submit their SIPs to the EPA will be delayed proportionately to the duration of the stay (i.e., around 2 years), it is uncertain whether the initial (2022) or final (2030) compliance dates will likewise be delayed. Subsequent to the issuance of the Stay Order, Virginia announced that it will continue development of a SIP. North Carolina and West Virginia have suspended development of SIPs at this time.

Due to this delay in the procedural status of the CPP, uncertainty has increased significantly both from a substantive and timing perspective. As acknowledged by the SCC, "significant uncertainty regarding the Clean Power Plan compliance existed at the time the Company filed its [2015] IRP and will likely continue for some time," including uncertainty as to the type of compliance program the states would ultimately select among the many pathways for compliance (i.e., one of the six identified programs under Intensity-Based or Mass-Based approaches). (2015 Plan Final Order at 5.) The ongoing litigation that is the subject of the Stay Order now creates additional uncertainty associated with the CPP's ultimate existence and the timing for compliance. As a result, the need for effective, comprehensive, long-range planning is even more important so that the Company can be prepared on behalf of its customers for the multitude of scenarios that the future may bring.

Reflecting this uncertainty and the need to plan for a variety of contingencies, the Company presents in this 2016 Plan five different alternative plans (collectively, the "Studied Plans") designed to meet the needs of its customers in a future both with or without a CPP. To assess a future without a CPP, the 2016 Plan includes an alternative designed using least-cost planning techniques and assuming no additional carbon regulation is implemented pursuant to the CPP (hereinafter identified as "Plan A: No CO_2 Limit" or "No CO_2 Plan"). Four additional alternative plans are designed to be compliant with the CPP as set forth in the final rule ("CPP-Compliant Alternative Plans" or "Alternative Plans") utilizing one of the four program options likely to be implemented in the Commonwealth of Virginia, where the bulk of the Company's generation assets are located (i.e., Intensity-Based Dual Rate, Intensity-Based State Average, Mass-Based Emissions Cap (existing units only) and Mass-Based Emissions Cap (existing and new units) programs). However, it should be noted that the Company considers it likely that there will be future regulation requiring it to address carbon and carbon emissions in some form beyond what is required today, even with the exact future of the CPP, at present, undetermined.

1.3.2 SCC's 2015 PLAN FINAL ORDER

As mentioned above, the SCC's Final Order found, in part, the 2015 Plan to be in the public interest and reasonable for filing as a planning document. Due to future regulatory and market uncertainties at the time of the filing of the 2015 Plan, including significant uncertainty surrounding the draft status of the CPP and the lack of knowledge of the requirements of the final CPP, ultimately released several months after the 2015 Plan was filed, the Company did not include a "Preferred Plan" or recommended path forward beyond the STAP. Instead, the 2015 Plan presented a set of alternative plans that represented potential future paths in an effort to test different resources strategies against plausible scenarios that might occur. Although opposition was raised to this approach, the 2015 Plan Final Order found that the Code of Virginia does not require the SCC to reject integrated resource plan filings that do not identify a stated preferred plan. (2015 Plan Final Order at 4.) Indeed, the SCC concluded, "The lack of a preferred plan is reasonable in this case given the substantial regulatory and planning uncertainty regarding the Clean Power Plan…." (2015 Plan Final Order at 6.)

In addition to its public interest and reasonableness findings, the 2015 Plan Final Order required that additional analyses in several areas be included in future integrated resource plan filings. The Company has complied with each bulleted requirement in the 2015 Plan Final Order, including the SCC's directive that the Company include with its filing an index that identifies the specific location(s) within the 2016 Plan that complies with each bulleted requirement ("Index"), which is attached to the filing letter included with this 2016 Plan filing. (2015 Plan Final Order at 18.) The Company is contemporaneously filing with the 2016 Plan a legal memorandum, which addresses legal issues raised in the 2015 Plan Final Order, as identified in the Index.

1.4 2016 PLAN

Prior to the Supreme Court stay, the Company believed it had more certainty as to a "Preferred Plan" or a recommended path forward in the 2016 Plan beyond the STAP based on the promulgation of the final CPP in August 2015. However, the Supreme Court's February 2016 stay of the procedural status of the CPP has created a regulatory environment that may be even more uncertain than existed prior to filing the 2015 Plan, which was based on a proposed rule that was significantly different from the final CPP.

As a result, there is significantly increased uncertainty surrounding the CPP, creating a circumstance in which the Company must legitimately analyze a future without the CPP, as well as one with the CPP implemented as promulgated in August 2015. Due to the recent timing of the Stay Order, the Company had insufficient time to analyze a future with a delayed implementation of the CPP or a future in which the CPP did not exist but carbon regulation took another form, a scenario the Company considers likely in the absence of the CPP. Therefore, at this time and as was the case in the 2015 Plan, the Company is unable to identify a "Preferred Plan" or a recommended path forward beyond the STAP. Rather in compliance with the 2015 Plan Final Order, the Company is presenting the five Studied Plans. The Company believes the Studied Plans represent plausible future paths for meeting the future electric needs of its customers while responding to changing regulatory requirements.

The first Studied Plan is designed using least-cost planning techniques and no additional carbon regulation:

- Plan A: No CO_2 Limit: This Studied Plan includes 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020, and also includes approximately 600 MW of North Carolina solar NUG generation that is expected to be online by the end of 2017. Plan A also reduces retirements of steam units, which continue to add fuel diversity to the Company's generation fleet and thereby help mitigate rate volatility to the Company's customers. Although Plan A: No CO_2 Limit is designed assuming a future without the CPP, the inclusion of the solar generation mentioned above positions the Company and its customers to either: (i) comply with the CPP in the event that the rule is ultimately upheld; or (ii) minimize compliance costs should the CPP be struck down. Should there be a future without the CPP or other additional carbon regulations, the Company would follow Plan A: No CO_2 Limit. However, as noted above, the Company believes it is likely that it will be subject to some form of carbon regulation in the future, even if the CPP is ultimately overturned by the federal courts. Also, as noted above, the Company lacked sufficient time to analyze during the development of this report the possible impact of alternative forms of carbon regulation on its long-range planning process.

In the event that the CPP is upheld as promulgated in August 2015, the 2016 Plan also includes the CPP-Compliant Alternative Plans that comply with the four likely programs that may be adopted by the Commonwealth of Virginia. These Alternative Plans in ascending order of compliance difficulty are:

- Plan B: Intensity-Based Dual Rate;
- Plan C: Intensity-Based State Average;
- Plan D: Mass-Based Emissions Cap (existing units only); and
- Plan E: Mass-Based Emissions Cap (existing and new units).

Plans B through E were designed using least cost analytical methods given the constraints of the CPP state compliance program options. Further, each of these Alternative Plans were designed in accordance with the final CPP with the intent that the Company would achieve CPP compliance independently, with no need to rely on purchasing CO_2 allowances or emission rate credits ("ERCs"). While the system was modeled as an "island," the Company expects markets for CPP ERCs and CO_2 allowances to evolve and favors CPP programs that encourage trading of ERCs and/or CO_2 allowances. Trading provides a clear market price signal which is the most efficient means of emission mitigation. Also, trading offers flexibility in the event of years with unit outages or non-normal weather. As the CPP trading markets materialize once the EPA model trading rules are finalized and as SIPs are developed, the Company will incorporate ERC and CO_2 allowance trading assumptions into its analysis. However, the Company maintains its island approach to trading is prudent for modeling purposes at this time in light of the uncertainty surrounding future markets for ERCs and CO_2 allowances that are not currently in place.

Based on this analysis, should the CPP be upheld in its current form, the Company believes that the adoption of a CPP compliance program option that is consistent with an Intensity-Based Dual Rate Program, as identified by the EPA, offers the most cost-effective and flexible option for achieving compliance with the CPP in the Commonwealth of Virginia. Indeed, as supported by the analysis conducted in this 2016 Plan, if the CPP is implemented in its current form, an Intensity-Based Dual Rate Program will be the least costly to the Company's customers and offer the Commonwealth the most flexibility over time in meeting environmental regulations and addressing economic development concerns. As further explained in Chapter 3, the flexibility associated with an Intensity-Based Dual Rate Program directly corresponds to the quantity of renewable resources, energy efficiency, and/or new nuclear generation available in Virginia through Company-built resources or programs, or resources purchased within or outside the Commonwealth. The availability of these resources needs to be contrasted against a Mass-Based program which, by definition, dictates adherence to hard caps on CO_2 emissions that limit the compliance options available to the Commonwealth, which in all likelihood, will further increase cost and rate volatility for customers. It is the Company's position that an Intensity-Based Dual Rate Program will provide the Commonwealth with the most CPP compliance flexibility, which, in turn, will help mitigate compliance costs over time.

Furthermore, the Company believes that a Mass-Based program that includes all units (existing and new), as modeled in Plan E: Mass-Based Emissions Cap (existing and new units) will be difficult to achieve by any state similar in EGU make-up to the Commonwealth of Virginia that anticipates economic growth. As shown in Chapter 6, compliance under Plan E: Mass-Based Emissions Cap (existing and new units) is not only the highest cost alternative of the Studied Plans, it also models the potential retirement of the Company's entire Virginia coal generation fleet, including VCHEC, which would result in additional economic hardship to the Virginia communities where these facilities are located.

As in the 2015 Plan, the Company will continue to analyze operational issues created by coal unit retirements. In addition to providing fuel diversity to the Company's existing portfolio, coal has significant operational benefits, notably the proven ability to operate as a baseload resource and capability of storing substantial fuel on site. During its 2015 Session, the Virginia General Assembly enacted SB 1349 with the goal, in part, of maintaining coal as a significant part of the Company's generation portfolio as long as possible, recognizing the regulatory threat to existing coal units posed by the CPP.

Going forward, the Company will continue to analyze both the operational implications and challenges of the Alternative Plans set forth in this document, as well as options for keeping existing generation, including coal units, operational when doing so is in the best interest of customers and the Commonwealth and also in compliance with federal and state laws and regulations. For the benefits of its customers and for Virginia's economy, the Company will also continue to work to maintain its long-standing service tradition of providing competitive rates, a diverse mix of generation, and reliable service. The Company continues to believe that these three factors are closely interrelated.

To evaluate external market and environmental factors that are subject to uncertainty and risk, the Company evaluated the Studied Plans using 3 scenarios and 12 rate design sensitivities, as discussed in Chapters 2 and 6. Further, the Company conducted a comprehensive risk analysis on the Studied Plans in an effort to help quantify the risks associated with each. The results of the analysis are presented in a Portfolio Evaluation Scorecard with respect to each of the Studied Plans.

There are several elements common to all of the Studied Plans. For example, all include VOWTAP, 12 MW (nameplate), as early as 2018, and 400 MW (nameplate) of Virginia utility-scale solar generation to be phased in from 2016 - 2020. These Plans also include 600 MW of North Carolina solar generation from NUGs under long-term contracts to the Company, as well as 7 MW (8 MW Direct Current ("DC")) from the Company's Solar Partnership Program ("SPP") by 2017. The SPP initiative installs Company-owned solar arrays on rooftops and other spaces rented from customers at sites throughout the service area. The Studied Plans also assume that all of the Company's existing nuclear generation will receive 20-year license extensions that lengthen their useful lives beyond the Study Period. The license extensions for Surry Units 1 and 2 are included in 2033 and 2034, respectively, as well as the license extensions for North Anna Units 1 and 2 in 2038 and 2040, respectively.

The electric power industry has been, and continues to be, dynamic in nature, with rapidly changing developments, market conditions, technology, public policy, and regulatory challenges. Certainly, the current stay of CPP implementation exemplifies such rapidly developing challenges, and the Company expects that these dynamics will continue in the future and will be further complicated by larger-scale governmental or societal trends, including national security considerations (which include infrastructure security), environmental regulations, and customer preferences. Therefore, it is prudent for the Company to preserve a variety of reasonable development options in order to respond to the future market, regulatory, and industry uncertainties which are likely to occur in some form, but difficult to predict at the present time.

Consequently, the Company recommends (and plans for), at a minimum, continued monitoring along with reasonable development efforts of the additional demand- and supply-side resources included in the Studied Plans as identified in Chapter 6. The Studied Plans are summarized in Figure 1.4.1.

Figure 1.4.1 - 2016 Studied Plans

Year		Compliant with Clean Power Plan				Renewables, Retirements, Extensions and DSM included in all Plans			
	Plan A: No CO_2 Limit	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)	Renewable	Retrofit	Retire	DSM[1]
2017						SLR NUG (204 MW)[3] SPP (7 MW)[3]		YT 1-2	
2018						VOWTAP	PP5 - SNCR		
2019	Greensville	Greensville	Greensville	Greensville	Greensville				
2020		SLR (200 MW)	SLR (400 MW)	SLR (200 MW)	SLR (800 MW)	VA SLR (400 MW)[6]			
2021		SLR(200MW)	SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2022	CT	3x1 CC SLR (200 MW)	3x1 CC SLR (400 MW)	3x1 CC SLR (200 MW)	2x1 CC CT SLR (800 MW)			YT 3[4], CH 3-4[4], CH 5-6[4], CL 1-2[4], MB 1-2[4]	Approved & Proposed DSM 330 MW by 2031 752 GWh by 2031
2023	CT	CT SLR (200 MW)	SLR (400 MW)	CT SLR (200 MW)	SLR (800 MW)				
2024		SLR (200 MW)	CT SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2025		SLR (100 MW)	SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2026			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2027			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2028	3x1 CC		SLR (200 MW)	SLR (200 MW)	SLR (600 MW)				
2029			SLR (200 MW)	SLR (200 MW)	NA3[2]			VCHEC[5]	
2030		3x1 CC	SLR (200 MW)	3x1 CC SLR (200 MW)					
2031			SLR (200 MW)	SLR (200 MW)					

Key: Retire: Remove a unit from service; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; NA3: North Anna 3; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SPP: Solar Partnership Program; VA SLR: Generic Solar built in Virginia; VCHEC: Virginia City Hybrid Energy Center; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Note: Generic SLR shown in the Studied Plans is assumed to be built in Virginia.

1) DSM capacity savings continue to increase throughout the Planning Period.

2) Earliest possible in-service date for North Anna 3 is September 2028, which is reflected as a 2029 capacity resource.

3) SPP and SLR NUG started in 2014. 600 MW of North Carolina Solar NUGs include 204 MW in 2017; 396 MW was installed prior to 2017.

4) The potential retirement of Yorktown Unit 3 and the potential retirements of Chesterfield Units 3-4 and Mecklenburg Units 1-2 are modeled in all of the CPP-Compliant Alternative Plans (B, C, D and E). The potential retirements of Chesterfield Units 5-6 and Clover Units 1-2 are modeled in Plan E. The potential retirements occur in December 2021, with capacity being unavailable starting in 2022.

5) The potential retirement of VCHEC in December 2028 (capacity unavailable starting in 2029) is also modeled in Plan E.

6) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 to 2020.

Common elements of the Studied Plans

The following are common to the Studied Plans through the Planning Period:

- **Demand-Side Resources (currently evaluated):**
  - approved DSM programs reaching approximately 304 MW by 2031;
  - proposed DSM programs reaching approximately 26 MW by 2031;
- **Generation under Construction:**
  - Greensville County Power Station, approximately 1,585 MW of natural gas-fired CC capacity by 2019;
  - Solar Partnership Program, consisting of 7 MW (nameplate) (8 MW DC) of capacity of solar distributed generation (or "DG") by 2017;
- **Generation under Development:**
  - Virginia utility-scale solar generation, approximately 400 MW (nameplate), to be phased in from 2016 - 2020;
    - Including Scott (17 MW), Whitehouse (20 MW) and Woodland (19 MW);
  - Virginia Offshore Wind Technology Advancement Project ("VOWTAP"), approximately 12 MW (nameplate) as early as 2018;
- **NUGs:**
  - 600 MW (nameplate) of North Carolina solar NUGs by 2017;
- **Retrofit:**
  - Possum Point Power Station Unit 5 "(Possum Point"), retrofitted with Select Non-Catalytic Reduction ("SNCR") by 2018;
- **Retirements:**
  - Yorktown Power Station ("Yorktown") Units 1 and 2 by 2017;
- **Extensions:**
  - Surry Units 1 and 2, license extensions of 20 years by 2033; and
  - North Anna Units 1 and 2, license extensions of 20 years by 2038.

In addition to the supply-side/DSM initiatives listed above that are common to all Studied Plans, the four CPP-Compliant Alternative Plans model the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Yorktown Unit 3 (790 MW) in 2022. Additional resources and retirements are included in the specified Alternative Plans below:

- **Generation Under Development:**
  - Plan E: Mass-Based Emissions Cap (existing and new units) includes 1,452 MW of nuclear generation.

- **Potential Generation:**
  - Plan A: No CO_2 Limit includes one 3x1 CC unit of approximately 1,591 MW and two combustion turbine ("CT")[2] plants of approximately 915 MW;
  - Plan B: Intensity-Based Dual Rate includes two 3x1 CC units of approximately 3,183 MW, one CT plant of 458 MW, as well as 1,100 MW (nameplate) of additional solar;
  - Plan C: Intensity-Based State Average includes one 3x1 CC unit of approximately 1,591 MW, one CT plant of 458 MW, as well as 3,400 MW (nameplate) of additional solar (3,600 MW by 2041);
  - Plan D: Mass-Based Emissions Cap (existing units only) includes two 3x1 CC units of approximately 3,183 MW, one CT plant of 458 MW, as well as 2,400 MW of additional solar (2,600 MW by 2041); and
  - Plan E: Mass-Based Emissions Cap (existing and new units) includes one 2x1 CC unit of approximately 1,062 MW, three CT plants of approximately 1,373 MW and 7,000 MW (nameplate) of additional solar.
- **Retirements:**
  - Plan E: Mass-Based Emissions Cap (new and existing units) includes the potential retirements of Chesterfield Units 5 (336 MW) and 6 (670 MW), and Clover Units 1 (220 MW) and 2 (219 MW) by 2022, as well as the potential retirement of VCHEC (610 MW) by 2029.

Figure 1.4.2 illustrates the renewable resources included in the Studied Plans over the Study Period (2017 - 2041).

Figure 1.4.2 – Renewable Resources in the Studied Plans

Resource	Nameplate MW	Plan A: No CO_2 Limit	Compliant with the Clean Power Plan			
			Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
Existing Resources	590	x	x	x	x	x
Additional VCHEC Biomass	27	x	x	x	x	x
Solar Partnership Program	7	x	x	x	x	x
Solar NUGs	600	x	x	x	x	x
VA Solar[1]	400	x	x	x	x	x
Solar PV	Varies	-	1,100 MW	3,600 MW	2,600 MW	7,000 MW
VOWTAP	12	x	x	x	x	x

Note: 1) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).

To meet the projected demand of electric customers and annual reserve requirements throughout the Planning Period, the Company has identified additional resources utilizing a balanced mix of supply- and demand-side resources and market purchases to fill the capacity gap shown in Figure 1.3.1. These resources are illustrated in Appendix 1A for all Studied Plans.

[2] All references regarding new CT units throughout this document refer to installation of a bank of two CT units.

The 2016 Plan balances the Company's commitment to operate in an environmentally-responsible manner with its obligation to provide reliable and reasonably-priced electric service. The Company has established a strong track record of environmental protection and stewardship and has spent more than $1.8 billion since 1998 to make environmental improvements to its generation fleet. These improvements have already reduced emissions by 81% for nitrogen oxide ("NO_x"), 96% for mercury ("Hg"), and 95% for sulfur dioxide ("SO_2") from 2000 levels.

Since numerous EPA regulations are effective, anticipated and stayed (as further shown in Figure 3.1.3.3), the Company continuously evaluates various alternatives with respect to its existing units. Coal-fired and/or oil-fired units that have limited environmental controls are considered at risk units. Environmental compliance offers three options for such units: 1) retrofit with additional environmental control reduction equipment, 2) repower (including co-fire), or 3) retire the unit.

With the background explained above, the retrofitted and retired units in the Studied Plans are as follows:

Retrofit

- 786 MW of heavy oil-fired generation installed with new SNCR controls at Possum Point Unit 5 by 2018 (Studied Plans).

Repower

- No units selected for repower at this time.

Retire

- 323 MW of coal-fired generation at Yorktown Units 1 and 2, to be retired by 2017 (Studied Plans);
- 790 MW of oil-fired generation at Yorktown Unit 3, to be potentially retired in 2022 (all CPP-Compliant Alternative Plans);
- 261 MW of coal-fired generation at Chesterfield Units 3 and 4, and 138 MW of coal-fired generation at Mecklenburg Units 1 and 2, all to be potentially retired in 2022 (all CPP-Compliant Alternative Plans);
- 1,006 MW of coal-fired generation at Chesterfield Units 5 and 6, and 439 MW of coal-fired generation at Clover Units 1 and 2, all to be potentially retired in 2022 (Plan E: Mass Emissions Cap (existing and new units)); and
- 610 MW of coal-fired generation at VCHEC, to be potentially retired in 2029 (Plan E: Mass Emissions Cap (existing and new units)).

In this way, the 2016 Plan provides options to address uncertainties associated with potential changes in market conditions and environmental regulations, while meeting future demand effectively through a balanced portfolio.

While the Planning Period is a 15-year outlook, the Company is mindful of the scheduled license expirations of Company-owned nuclear units: Surry Unit 1 (838 MW) and Surry Unit 2 (838 MW) in 2032 and 2033, respectively, and North Anna Unit 1 (838 MW) and North Anna Unit 2 (834 MW) in 2038 and 2040, respectively. At the current time, the Company believes it will be able to obtain license extensions on all four nuclear units at a reasonable cost; therefore, it has included the extensions in all Studied Plans. If the nuclear extensions were not to occur, the Mass-Based Emissions Cap (existing and new units) Program option would be materially impacted. In fact, Plan E: Mass-Based Emissions Cap (existing and new units) would require approximately 8,000 MW (nameplate) of additional solar by 2041. Therefore in total, Plan E: Mass-Based Emissions Cap (existing and new units) without the nuclear extensions would require North Anna 3 and approximately 16,000 MW (nameplate) solar which would not only increase cost significantly, it could potentially cause system operation problems.

While not definitively choosing one plan or a combination of plans beyond the STAP, the Company remains committed to pursuing the development of resources that meet the needs of customers discussed in the Short-Term Action Plan, while supporting the fuel diversity needed to minimize risks associated with changing market conditions, industry regulations, and customer preferences. Until such time as the CPP is upheld or struck down, the Company plans to further study and assess options as if the CPP as promulgated in August 2015 were in place, so that the Company will be prepared to offer a more definitive plan or combination of plans as the future becomes clearer.

1.5 RATE IMPACT OF CPP-COMPLIANT ALTERNATIVE PLANS (2022, 2026, 2030)

Figures 1.5.1 and 1.5.2 reflect the percentage and dollar increase in a typical 1,000 kWh/month residential customer's monthly bill for each CPP-Compliant Alternative Plan, for the years 2022, 2026 and 2030, as compared to Plan A: No CO_2 Limit. A more detailed discussion on the Rate Impact Analysis is provided in Section 6.7. As shown in the figures below, implementation of Mass-Based compliance strategies would have a much greater impact on customer bills than Intensity-Based. For example, the Company estimates that Plan E: Mass-Based Emissions Cap (existing and new units) would raise the typical residential bill on average approximately 22% during the 2022 through 2030 time period, as compared to Plan A: No CO_2 Limit. Whereas, Plan B: Intensity-Based Dual Rate would raise customer bills 3% during the same period.

Figure 1.5.1 – Residential Monthly Bill Increase as Compared to Plan A: No CO_2 Limit (%)

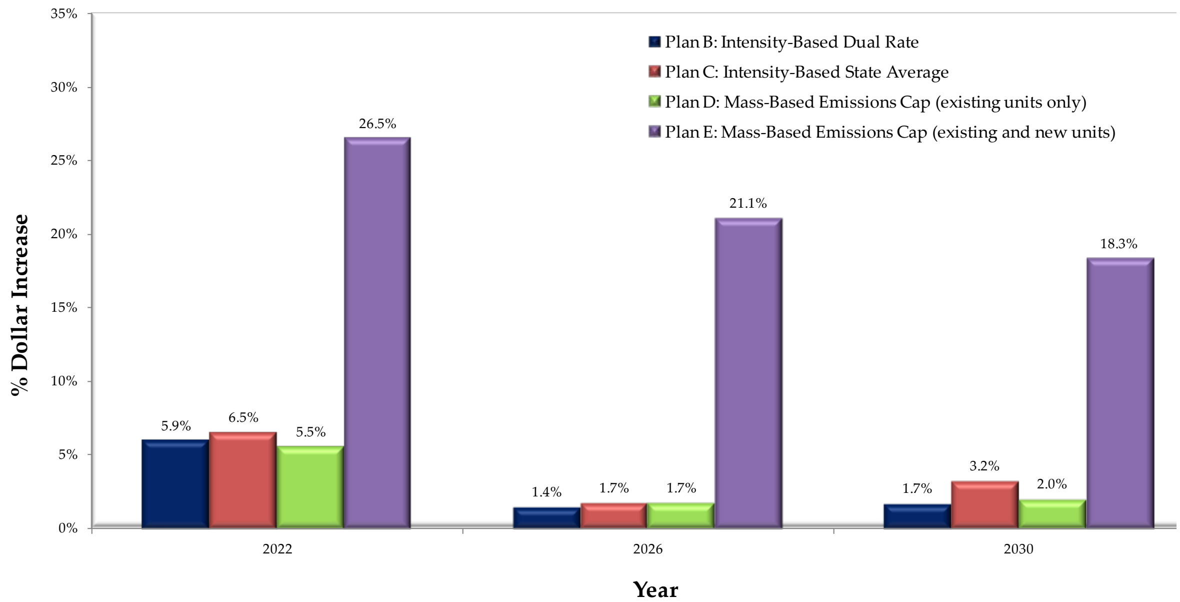
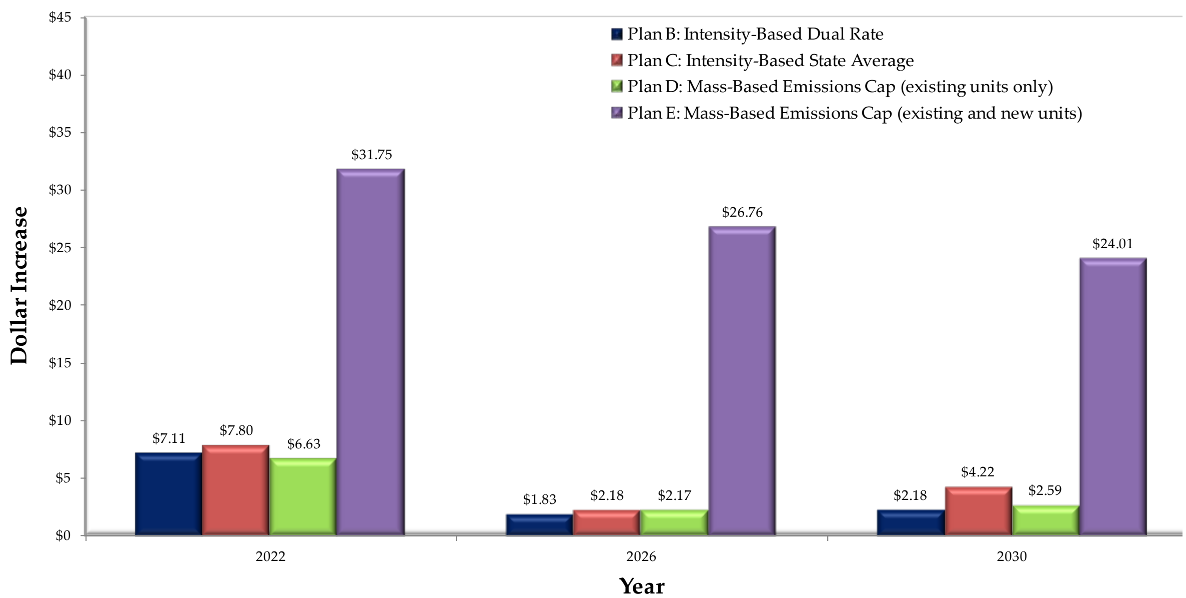


Figure 1.5.2 – Residential Monthly Bill Increase as Compared to Plan A: No CO_2 Limit ($)



CHAPTER 2 – LOAD FORECAST

2.1 FORECAST METHODS

The Company uses two econometric models with an end-use orientation to forecast energy sales. The first is a customer class level model ("sales model") and the second is an hourly load system level model ("system model"). The models used to produce the Company's load forecast have been developed, enhanced, and re-estimated annually for over 20 years, but have remained substantially consistent year-over-year.

The sales model incorporates separate monthly sales equations for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other Load Serving Entities ("LSEs") in the Dominion Zone ("DOM Zone"), all of which are in the PJM RTO. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load.

Variables included in the monthly sales equations are as follows:

- **Residential Sales equation:** Income, electric prices, unemployment rate, number of customers, appliance saturations, building permits, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Commercial Sales equation:** Virginia Gross State Product ("GSP"), electric prices, natural gas prices, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Industrial Sales equation:** Employment in manufacturing, electric prices, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Public Authorities Sales equation:** Employment for Public Authority, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Street and Traffic Lighting Sales equation:** Number of residential customers and calendar month variables to capture seasonal impacts.
- **Wholesale Customers and Other LSEs Sales equations:** A measure of non-weather sensitive load derived from the residential equation, heating and air-conditioning appliance stocks, number of days in the month, weather, and calendar month variables to capture seasonal and other effects.

The system model utilizes hourly DOM Zone load data and is estimated in two stages. In the first stage, the DOM Zone load is modeled as a function of time trend variables and a detailed specification of weather involving interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations. The parameter estimates from the first stage are used to construct two composite weather variables, one to capture heating load and one to capture cooling load. In addition to the two weather concepts derived from the first stage, the second stage equation uses estimates of non-weather sensitive load derived from the sales model and residential heating and cooling appliance stocks as explanatory variables. The hourly model also uses calendar month variables to capture time of day, day of week, holiday, other seasonal effects and unusual events such as hurricanes. Separate equations are estimated for each hour of the day.

Hourly models for wholesale customers and other LSEs within the DOM Zone are also modeled as a function of the DOM Zone load since they face similar weather and economic activity. LSE peaks and energy are based on a monthly 10-year average percentage. These percentages are then applied to the forecasted zonal peaks and energy to calculate LSE peaks and energy. The DOM LSE load is derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations are used as the total load obligation for the purpose of this 2016 Plan.

Forecasts are produced by simulating the model over actual weather data from the past 30 years along with projected economic conditions. Sales estimates from the sales model and energy output estimates from the system model are compared and reconciled appropriately in the development of the final sales, energy, and peak demand forecast that is utilized in this 2016 Plan.

2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The Company is typically a summer peaking system; however, during the winter period of both 2014 and 2015, all-time DOM Zone peaks were set at 19,785 MW and 21,651 MW respectively. The historical DOM Zone summer peak growth rate has averaged about 1.2% annually over 2001 - 2015. The annual average energy growth rate over the same period is approximately 1.3%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figure 2.2.1 and Figure 2.2.2. Figure 2.2.1 also reflects the actual winter peak demand. DOM LSE peak and energy requirements are both estimated to grow annually at approximately 1.5% throughout the Planning Period. Additionally, a 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown at Virginia and North Carolina levels are provided in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used in the development of this 2016 Plan. Finally, the three-year historical load and 15-year projected load for wholesale customers are provided in Appendix 3L.

Figure 2.2.1 - DOM Zone Peak Load

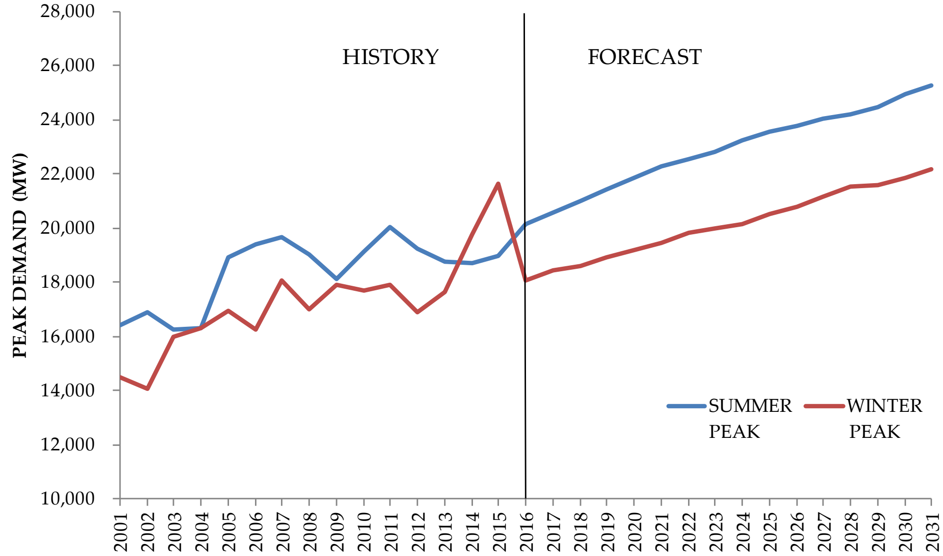


Figure 2.2.2 - DOM Zone Annual Energy

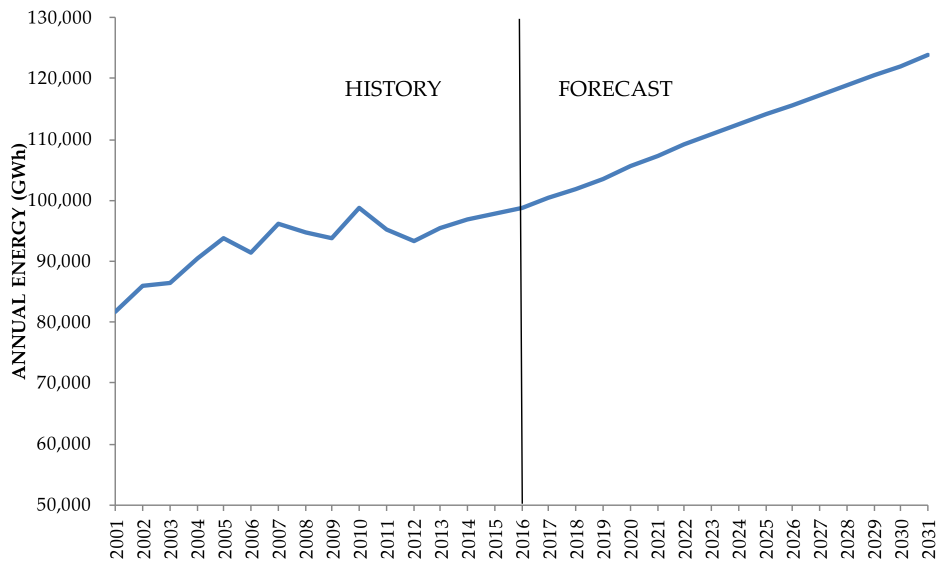


Figure 2.2.3 summarizes the final forecast of energy sales and peak load over the next 15 years. The Company's wholesale and retail customer energy sales are estimated to grow at annual rates of approximately 0.6% and 1.7%, respectively, over the Planning Period as shown in Figure 2.2.3. Historical and projected growth rates can diverge for a number of reasons, including weather and economic conditions.

Figure 2.2.3 - Summary of the Energy Sales & Peak Load Forecast

	2016	2031	Compound Annual Growth Rate (%) 2016 - 2031
DOMINION LSE			
TOTAL ENERGY SALES (GWh)	82,329	105,068	1.6%
Retail	80,797	103,383	1.7%
Residential	30,683	38,467	1.5%
Commercial	31,037	45,135	2.5%
Industrial	8,421	7,553	-0.7%
Public Authorities	10,363	11,868	0.9%
Street and Traffic Lighting	294	360	1.4%
Wholesale (Resale)	1,531	1,684	0.6%
SEASONAL PEAK (MW)			
Summer	17,620	22,103	1.5%
Winter	15,612	19,127	1.4%
ENERGY OUTPUT (GWh)	86,684	108,636	1.5%
DOMINION ZONE			
SEASONAL PEAK (MW)			
Summer	20,127	25,249	1.5%
Winter	18,090	22,162	1.4%
ENERGY OUTPUT (GWh)	98,868	123,900	1.5%

Note: All sales and peak load have not been reduced for the impact of DSM.

Figures 2.2.4 and 2.2.5 provide a comparison of DOM Zone summer peak load and energy forecasts included in the 2015 Plan, 2016 Plan, and PJM's load forecast for the DOM Zone from its 2015 and 2016 Load Forecast Reports.[3]

[3] See www.pjm.com/~/media/documents/reports/2015-load-forecast-report.ashx; see also http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx

Figure 2.2.4 - DOM Zone Peak Load Comparison

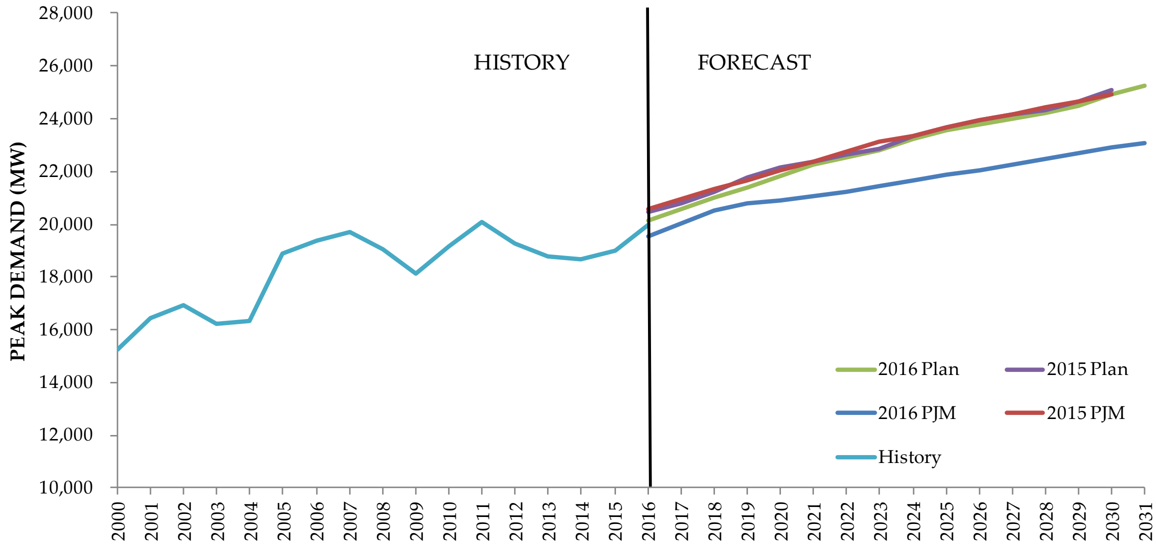
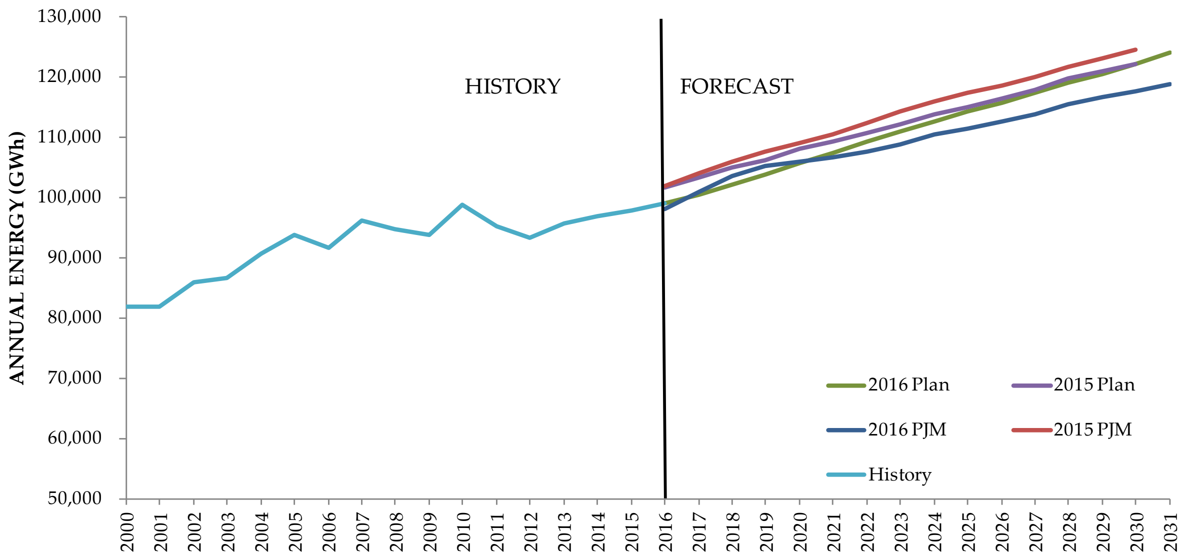


Figure 2.2.5 - DOM Zone Annual Energy Comparison



The Company made an adjustment to its load forecasting to reflect data center growth (both new and expanded campuses) contributing to summer peak and hourly loads starting in 2016. The estimate is a combination of the Company's internal forecast and a study performed by Quanta Technology, Inc. With that exception, the Company's IRP load forecasting methodology has remained consistent over the years, while PJM's 2016 load forecasting methodology underwent significant changes from what was used in 2015. Key changes in PJM's 2016 load forecast include the following:

- The simulation for normal weather was shortened from 41 years to 21 years (1994-2014).
- Variables were added to represent trends in equipment/appliance saturation and energy efficiency.
- The economic region for Virginia was changed to a GSP to reflect growth in Northern Virginia. PJM previously used three metropolitan service areas in Virginia (Richmond, Norfolk, and Roanoke).
- Solar distributed generation was incorporated in the historical load data used to estimate the model. PJM now includes a separately-derived solar forecast to adjust its load forecast.

There have always been many differences between PJM's and the Company's forecasting models and methodologies. Key differences this year include:

- The Company's forecast is based on a "bottom-up approach" and consists of two regression models, one based on hourly load data and the other based on actual customer sales data by class. PJM's forecasting model is based on a "top down approach" using daily energy and daily peak loads.
- The Company's customer sales model includes price elasticity of demand, whereas PJM's model does not.
- The Company's model uses 30 years of historical data to assess normal weather, whereas PJM's model now uses 21 years of historical weather.
- The model estimation period also differs – the Company uses 30 years while PJM's estimation period runs from January 1998 through August 2015.

The economic and demographic assumptions that were used in the Company's load forecasting models were supplied by Moody's Economy.com, prepared in September 2015, and are included as Appendix 2K. Figure 2.2.6 summarizes the economic variables used to develop the sales and peak load forecasts used in this 2016 Plan.

Figure 2.2.6 - Major Assumptions for the Energy Sales & Peak Demand Model

	2016	2031	Compound Annual Growth Rate (%) 2016 - 2031
DEMOGRAPHIC:			
Customers (000)			
Residential	2,275	2,723	1.21%
Commercial	241	279	0.96%
Population (000)	8,460	9,457	0.75%
ECONOMIC:			
Employment (000)			
State & Local Government	542	608	0.76%
Manufacturing	235	204	-0.94%
Government	712	778	0.59%
Income ($)			
Per Capita Real disposable	42,738	54,429	1.63%
Price Index			
Consumer Price (1982-1984 = 100)	242	345	2.40%
VA Gross State Product (GSP)	451	616	2.09%

The forecast for the Virginia economy is a key driver in the Company's energy sales and load forecasts. Like most states, the Virginia economy was adversely impacted by the recession of 2007 - 2009. As compared to other states, however, the Virginia economy was also negatively impacted by federal government budget cuts of 2013 that resulted from the sequestration. This latter event further adversely affected Virginia due to its dependency on federal government spending, particularly in the area of defense. In spite of these economic hurdles, the Virginia economy continued to grow at an annual average real gross domestic product growth rate of approximately 0.7% during the 2007 through 2014 timeframe. Furthermore, during that same time period, Virginia's annual unemployment rate averaged approximately 2% below the national rate. As of December 2015, the seasonally-adjusted unemployment rate in Virginia approached 4.2%, approximately 0.8% below the national unemployment rate.

Going forward, the Virginia economy is expected to rebound considerably within the Planning Period. The 2015 Budget Bill approved by the President and the U.S. Congress has significantly increased the level of federal defense spending for fiscal years 2016 and 2017, which should benefit the Virginia economy. The Commonwealth has also been aggressive in its economic development efforts, a major priority for Virginia state government and the current Governor.

Housing starts and associated new homes are significant contributors to electric sales growth in the Company's service territory. The sector saw significant year-over-year declines in the construction of new homes from 2006 through 2010 and began showing improvements in 2012. According to

Moody's, Virginia is expected to show significant improvement in housing starts in 2017, which is reflected as new customers in the load forecast.

Another driver of energy sales and load forecasts in the Company's service territory is new and existing data centers. The Company has seen significant interest in data centers locating in Virginia because of its proximity to fiber optic networks as well as low-cost, reliable power sources.

On a long-term basis, the economic outlook for Virginia remains positive. Over the next 15 years, real per-capita income in the state is expected to grow about 1.6% per year on average, while real GSP is projected to grow more than 2.0% per year on average. During the same period, Virginia's population is expected to grow steadily at an average rate of approximately 0.75% per year. Further, after the Atlantic Coast Pipeline ("ACP") is completed, new industrial, commercial and residential load growth is expected to materialize as additional low-cost natural gas is made available to the geographical region.

2.3 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The three-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 2I. Additionally, Appendix 2J provides the reserve margins for a three-year actual and 15-year forecast.

2.4 ECONOMIC DEVELOPMENT RATES

As of March 1, 2016, the Company has four customers in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 28 MW. There are no customers in Virginia under a self-generation deferral rate.

As of March 1, 2016, the Company has one customer in North Carolina receiving service under economic development rates with approximately 1 MW of load. There are no customers in North Carolina under a self-generation deferral rate.

2.5 RESIDENTIAL AND NON-RESIDENTIAL RATE DESIGN ANALYSIS

SB 956

Pursuant to the enactment clause of SB 956[4] and the SCC's Final Order on the 2011 Plan (Case No. PUE-2011-00092), the Company developed a rate design analysis to: 1) address the appropriateness of a declining block residential rate for winter months; and 2) identify potential, generalized rate designs.

Additionally, in its Final Orders on the 2013 Plan (Case No. PUE-2013-00088) and 2015 Plan (Case No. PUE-2015-00035), the SCC addressed the rate design analysis and directed the Company to consider further rate design issues in subsequent Plans, including directives to:

- Continue to model and refine alternative rate design proposals, including alternative rate designs for customer classes in addition to the residential class;

[4] 2013 Va. Acts of Assembly, Ch. 721, Enactment Clause 1 (approved March 25, 2013, effective July 1, 2013).

- Examine the appropriateness of the residential winter declining block rate and present other potential alternatives for the residential winter declining block rate;
- Analyze how alternative rate designs may impact demand and the Company's resource planning process due to price elasticity;
- Continue to report on a residential rate design alternative that includes a flat winter generation rate, an increased inclining summer generation rate, and no changes to distribution rates;
- Continue to report on a residential rate design alternative that includes an increased differential between summer and winter rates for residential customers above the 800 kilowatt-hour ("kWh") block and no change in distribution rates;
- Continue to report on alternative GS-1 rate designs;
- Expand its analysis of alternative rate designs to other non-residential rate classes;
- Investigate an alternative rate design for Rate Adjustment Clauses ("RACs") that includes a summer rate with an inclining block rate component combined with a flat winter rate;
- Analyze whether maintaining the existing rate structure is in the best interest of residential customers;
- Evaluate options for variable pricing models that could incent customers to shift consumption away from peak times to reduce costs and emissions; and
- Evaluate and include various rate-design proposals as part of the mix of DSM-related compliance options that it will be modeling for next May's Plan filing.

2.5.1 RESIDENTIAL RATE SCHEDULE 1 BACKGROUND

The development of the residential rate structure was designed to: 1) reduce the divergence of summer and winter peaks;[5] and 2) enhance the efficiency of the Company's infrastructure by fully utilizing additional generation capacity that is available in the winter due to the level of summer generation capacity required for reliability purposes. This was accomplished through the creation of a summer winter differential which provided the tail block in the summer months that would increase from the first block. To achieve this increase in the summer, revenue was taken from the tail block in the non-summer months, which resulted in a lower non-summer tail block rate.

2.5.2 ALTERNATIVE RATE DESIGN ANALYSIS

The Company's Customer Rates Group developed five alternative rate designs to be used as model inputs to its load forecasting models. All alternative rate designs are revenue neutral.

[5] The Company's annual peak demand for electricity typically occurs in the four-month summer period of June through September, primarily due to loads associated with air conditioning. However, the Company has recorded winter peaks in 2014 and 2015, with an all-time record breaking peak load of 18,688 MW on Friday, February 20, 2015, due to extreme cold weather experienced over several days.

Alternative Residential Rate Design Analysis to the Company's Existing Base Rates:

- Study A: Flat winter generation rate and inclining summer generation rate; and
- Study B: Increased differential between summer and winter generation rates for residential customers above the 800 kWh block; i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month with no changes to distribution rates.

Alternative Residential Rate Design for RACs Only:

- Study C: Alternative rate analysis for Schedule 1;
- Study D: Alternative rate analysis for flat winter generation rate and increased inclining summer generation rate; and
- Study E: Alternative rate analysis for increased differential between summer and winter rates for residential customers above the 800 kWh block with no changes to distribution rates.

Figure 2.5.2.1 reflects the sensitivities for each of the alternative residential rate designs compared against existing rates. The Company's existing Schedule 1 residential rates are included in the basecase for all Studied Plans. For each alternative residential rate studied, the impact on the overall net present value ("NPV") of each Studied Plan is reflected accordingly. For example, compared to existing Schedule 1 residential rates in the Plan A: No CO_2 Limit, Residential Study A (Flat winter generation rate and inclining summer generation rate) will be 0.21% less costly. Also, compared to the existing Schedule 1 residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), Residential Study E (Increased differential between summer and winter rates with an alternative RAC design for the generation riders) will be 0.21% less costly (26.61% - 26.40%).

Figure 2.5.2.1 – Residential Rate Study Comparison

		Subject to the EPA's Clean Power Plan			
Study	Plan A: No CO_2 Limit	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
A	-0.21%	10.40%	12.12%	11.26%	26.29%
B	-0.15%	10.45%	12.16%	11.31%	26.33%
C	-0.10%	10.50%	12.19%	11.35%	26.35%
D	-0.09%	10.50%	12.20%	11.35%	26.35%
E	-0.05%	10.55%	12.25%	11.40%	26.40%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

2.5.3 RESULTS OF THE ALTERNATIVE RATE DESIGN ANALYSIS

The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand.

The average calculation of elasticity over the modeled sensitivities for Schedule 1 customers is approximately 0.06, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.06%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure on total sales and peak levels. For more detail regarding the Alternative Residential Rate Analysis, see Appendix 2L.

> 1% increase in the average residential price of electricity would reduce average consumption by approximately 0.06%.

2.5.4 ALTERNATIVE NON-RESIDENTIAL SCHEDULE GS-1 AND SCHEDULE 10 RATE DESIGN

The Company's Customer Rates Group developed six alternative non-residential rate designs to be used as model inputs to the Company's load forecasting models. Alternative Non-Residential GS-1 and Schedule 10 rate designs were intended to be revenue neutral on a rate design basis, and were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models.

The Company considered alternative rate designs for GS-3 (Secondary Voltage) and GS-4 (Primary Voltage) that would extend the peak period rate into the weekend, but these rates are properly designed for customers. Customers on these rates have a demand charge that sends a price signal to manage their electricity consumption. In addition, these customers are typically high load factor customers and are not likely to respond to a peak rate extended into the weekend. Rate Schedule GS-1 was chosen for this analysis because the Company does not offer a non-pilot time-of-use ("TOU") alternative for the GS-1 customer class. The six rate designs used to compare against the current declining block rates in the winter months are listed below.

Alternative Non-Residential GS-1 Rate Designs to the Company's Existing Base Rates:

- Study A: Flat rates during summer and winter for both distribution and generation;
- Study B: Inclining block rates during summer and winter for generation with flat distribution rates;
- Study C: Flat winter generation rates with no change in the existing summer generation rates or existing distribution rates;
- Study D: Increased differential between summer and winter rates for commercial customers above the 1,400 kWh block; i.e., an increase in summer rates and a decrease in winter rates for commercial customers using more than 1,400 kWh per month with no changes to distribution rates; and
- Study E: Flat winter generation rate and increased inclining summer generation rate.

Alternative Non-Residential Rate Design for Schedule 10:

- Study F: Increase the on-peak rate for "A" days during the peak on and off-peak seasons with no changes to the off-peak rate. Reduce the peak and off-peak rates for "B" and "C" days for both the peak and off-peak seasons.

Figure 2.5.4.1 reflects the sensitivities for each of the alternative non-residential rate designs compared against existing GS-1 rates (Studies A-E) and Schedule 10 (Study F). The Company's existing GS-1 rates and Schedule 10 are included in the basecase for all Studied Plans. For each alternative non-residential rate studied, the impact on the overall NPV of each Studied Plan is reflected accordingly. For example, compared to existing GS-1 non-residential rates in the Plan A: No CO_2 Limit, Non-Residential Study A (Flat rates during the summer and winter for both distribution and generation) will be 0.03% less expensive. Another example would be that compared to the existing Schedule 10 non-residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), Non-Residential Study F (Increase the on-peak rate for "A" days during the peak and off-peak seasons with no change to the off-peak rate and reduce the peak and off-peak rates for "B" and "C" days) will be 0.17% less costly (26.61% - 26.44%).

Figure 2.5.4.1 – Non-Residential Rate Study Comparison

Study		Subject to the EPA's Clean Power Plan			
	Plan A:	Plan B:	Plan C:	Plan D:	Plan E:
	No CO_2 Limit	Intensity-Based Dual Rate	Intensity-Based State Average	Mass-Based Emissions Cap (existing units only)	Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
A	-0.03%	10.57%	12.26%	11.41%	26.41%
B	-0.04%	10.56%	12.26%	11.41%	26.41%
C	-0.04%	10.56%	12.25%	11.41%	26.41%
D	-0.05%	10.56%	12.25%	11.40%	26.41%
E	-0.05%	10.55%	12.25%	11.40%	26.40%
F	-0.07%	10.56%	12.27%	11.41%	26.44%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

2.5.5 RESULTS OF THE ALTERNATIVE NON-RESIDENTIAL RATE ANALYSIS

The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities for GS-1 customers is approximately 0.4, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.4%. The average calculation of elasticity over the modeled sensitivities for GS-3 and GS-4 customers on Schedule 10 rates is approximately -0.11, meaning a 1% increase in the average price of electricity on "A" days would reduce average consumption by approximately 0.11%. The elasticity suggests that increases

> 1% increase in the average price of electricity for GS-1 customers would reduce average consumption by approximately 0.4%.
>
> 1% increase in the average price of electricity on "A" days for GS-3 and GS-4 customers on Schedule 10 rates would reduce average consumption by approximately 0.11%.

in price, holding all other variables constant, will place downward pressure on sales and peak levels. Such an impact from recognition of a price elasticity effect on the generation and resource plan should also be recognized in the design of electricity rates. For more detail regarding the Alternative Non-Residential Rate Analysis, see Appendix 2M.

2.5.6 APPROPRIATENESS OF THE DECLINING BLOCK RATE

Based on the results of these studies, the Company maintains that the declining winter block rate continues to be an appropriate rate mechanism to utilize generation capacity efficiently on an annualized basis, control summer peak growth, and keep rates low and affordable, particularly for electric heating customers. While the study results presented begin to reveal correlations and relationships between price and quantity, these analyses should be viewed as initial benchmark studies of alternative rate designs.

Large pricing changes make the model outputs less reliable than would be desired to establish alternative rate designs that may be considered just and reasonable. Additionally, the studies contemplate an instantaneous shift in rate design, rather than a long-term incremental approach to rate changes which allows customers to react and avoid large rate increases. For example, customers' investments in long-term electric-based infrastructure, such as heat pumps, could be significantly impacted under an alternative rate studies in a negative fashion.

Several natural gas utilities also offer declining block rates during winter months. Consideration must be given to the impact that adjusting, or eliminating, declining block rates will have on fuel switching.

The Company continues to support the current rate design for Schedule 1 and believes it is in customers' best interest to not stray far from the current design. The current design does send a price signal to customers to reduce consumption to avoid future capacity obligations. By calling for a more rigorous analysis of the Schedule 1 residential rate design, such analysis would need to consider the types of costs (fixed, demand-related fixed, and variable) that have been incurred and the way such costs are recovered through rates. The current two part rate design in Schedule 1 does not represent an approach to cost recovery through rates consistent with the way that costs have actually been incurred. Distribution costs are fixed and either classified as customer or demand-related. Transmission costs are fixed and are demand-related. The majority of production costs are fixed and demand-related. Fuel costs are variable and are energy-related. Yet over 93% of a 1,000 kWh/month typical residential customer's bill is recovered through charges that vary with kWh consumption. In contrast, for medium and large general service customer classes, the Company's standard tariffs reflect a three-part rate design that is more consistent with the way that costs have actually been incurred.

To address the question about whether the existing rate structure is in the best interest of residential customers, one must consider that there are over 2 million customers taking service on Rate Schedule 1, and any change to the current design structure would be a major undertaking with unknown customer impacts and create questions about customer acceptance. The question of customer acceptance with regard to design changes to Rate Schedule 1 may be a matter of public policy and not solely a question of achieving cost recovery through rates consistent with cost causation.

Proper rate design is guided by many principles and objectives but chief among them should be that rates reasonably recover costs. Important considerations during the rate design process include factors such as:

- the impact of rate design on customer bills;
- the stability of customer bills;
- the difference in utility system costs based upon seasons, day of the week, and time of day;
- cost control through encouraging price response to avoid future utility system costs;
- the impact on bills for customers using various methods of space conditioning;
- the availability of other competitive fuel sources to provide space conditioning;
- the availability of voluntary/optional rate schedules within each customer class as it relates to recovery of the revenue requirement apportioned to the class;
- the competitiveness of customer bills (and therefore rates) with other utilities and, in particular, with regard to the southeastern peer group;
- delivery and measurement technologies available for use to measure usage for the purpose of billing customers; and
- other factors and policies historically determined by the SCC to be appropriate in establishing rates.

Underlying all of these considerations, rate design should provide the means to recover just and reasonable utility system costs in a manner that is: (i) consistent with the way costs are incurred; (ii) fair to the entire body of customers; (iii) fair to each customer class; (iv) fair to customers within an individual class; and (v) fair to the utility's shareholders.

2.5.7 MODEL AN ALTERNATIVE RATE DESIGN (RESIDENTIAL DYNAMIC PRICING) AS A LOAD REDUCER AS PART OF THE MIX OF DSM-RELATED COMPLIANCE OPTIONS

This study presents the results of an analysis to implement dynamic pricing in lieu of Schedule 1 rates for the residential population in Virginia. The Company examined energy usage data from approximately 20,000 residential customers with Advanced Metering Infrastructure ("AMI") meters on Schedule 1 rates and developed a regression model to predict the effects of different pricing signals on peak and energy demand for the calendar year 2015. The Company used the same cooling/heating season periods, "A/B/C" day classifications and dynamic rates that were used in the Company's Dynamic Pricing Pilot ("DPP"). Unfortunately, this regression modeling approach was necessary because data obtained from the actual DPP customers resulted in a price elasticity that was counterintuitive because as prices increased, demand increased. This may be the result of data bias due to a small sample size. Given this perceived anomaly in the DPP customer data, the Company elected to complete this analysis using the regression modeling method described above.

The dynamic pricing regression modeling results follow expectations such that increases in prices lead to lower peak demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities for residential dynamic pricing is approximately -0.75, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.75%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure on system peak levels. Econometric analysis of the residential response to different price signals effectively suggests a decrease in peak demand and usage during peak months and a net kWh usage increase during shoulder months. The -0.75 price elasticity determined in this analysis is extraordinarily high, however, and also questionable as to its validity. This is likely the result of developing the regression model with data from customers who are currently being serviced under Schedule 1 rates. A more appropriate model would be one developed using data from customers that are currently on DPP rates but as was mentioned previously, the results from the model using the actual data from DPP customers produced counterintuitive results and could not be utilized in this analysis.

> 1% increase in the average residential price of electricity would decrease average consumption of dynamic pricing customers by approximately 0.75%.

For more detail regarding the Alternative Residential Dynamic Pricing Rate Analysis, see Appendix 2N.

Figure 2.5.7.1 reflects the sensitivities for the alternative residential dynamic pricing rate design compared against existing rates. The Company's existing Schedule 1 residential rates are included in the basecase for all Studied Plans. The impact on the NPV of the Studied Plan is reflected accordingly. For example, compared to existing Schedule 1 residential rates in the Plan A: No CO_2 Limit, the Residential Dynamic Pricing Rate will be 0.15% more costly. Also, compared to the existing Schedule 1 residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), the Residential Dynamic Pricing Rate will be 0.08% more costly (26.69% - 26.61%).

Figure 2.5.7.1 – Residential Dynamic Pricing Rate Study Comparison

		Subject to the EPA's Clean Power Plan			
	Plan A:	Plan B:	Plan C:	Plan D:	Plan E:
Study	No CO_2 Limit	Intensity-Based Dual Rate	Intensity-Based State Average	Mass-Based Emissions Cap (existing units only)	Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
Dynamic Pricing	0.15%	10.78%	12.50%	11.64%	26.69%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

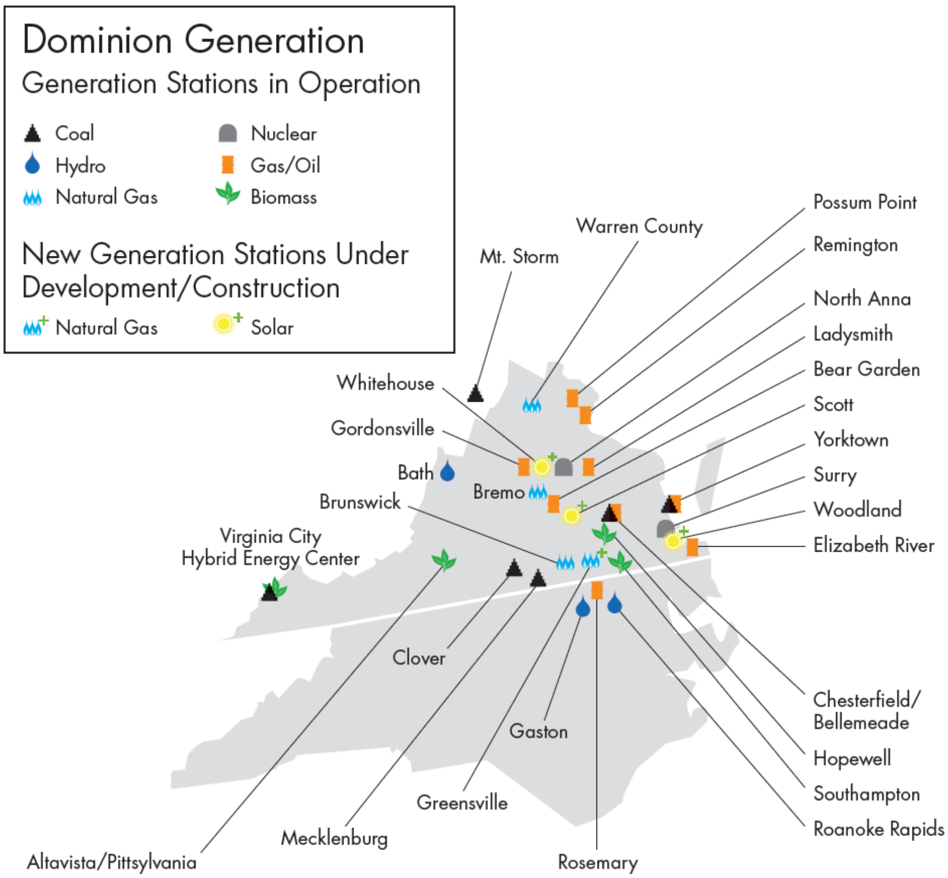
CHAPTER 3 – EXISTING & PROPOSED RESOURCES

3.1 SUPPLY-SIDE RESOURCES

3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 3.1.1.1. This diverse fleet of 99 generation units includes 4 nuclear, 14 coal, 4 natural gas-steam, 10 CCs, 41 CTs, 4 biomass, 2 heavy oil, 6 pumped storage, and 14 hydro units with a total summer capacity of approximately 19,829 MW.[6] The Company's continuing operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying load conditions.

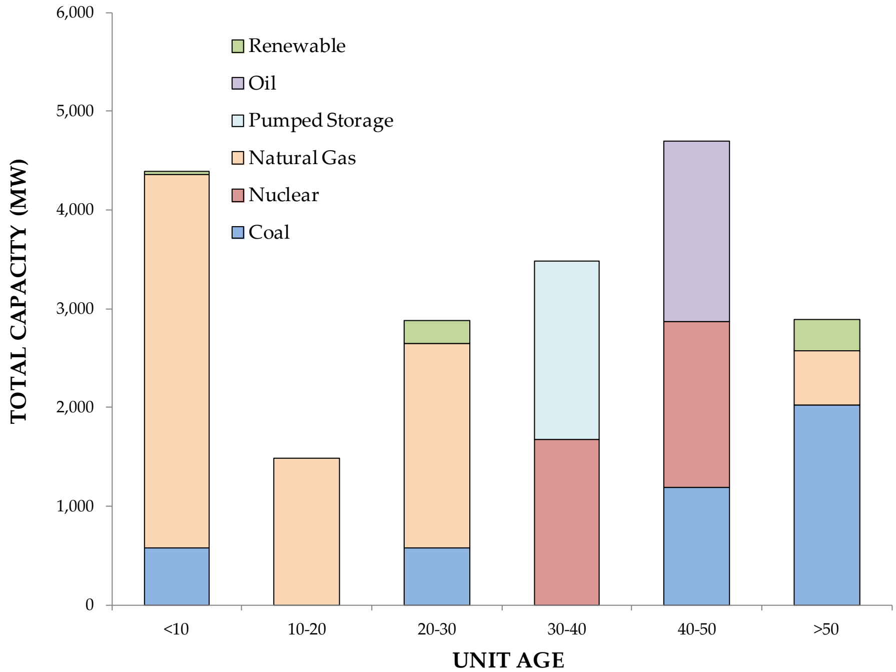
Figure 3.1.1.1 - Dominion Virginia Power Generation Resources



The Company owns a variety of generation resources that operate using a diverse set of fuels. The largest proportion of the Company's generation resources has operated for 40 to 50 years, followed by a large number of units that have operated for less than 10 years and units that have operated for 30 to 40 years. Figure 3.1.1.2 shows the demographics of the entire existing generation fleet.

[6] All references to MW in Chapter 3 refer to summer capacity unless otherwise noted. Winter capacities for Company-owned generation units are listed in Appendix 3A.

Figure 3.1.1.2 - Generation Fleet Demographics



Note: Renewable resources constitute biomass, wind, solar and hydro units.

Figure 3.1.1.3 illustrates that the Company's existing generation fleet is comprised of a mix of generation resources with varying operating characteristics and fueling requirements. The Company also has contracted 1,277 MW of fossil-burning and renewable NUGs, which provide firm capacity as well as associated energy and ancillary services to meet the Company's load requirements. Appendix 3B lists all of the NUGs in the 2016 Plan. The Company's planning process strives to maintain a diverse portfolio of capacity and energy resources to meet its customers' needs.

Figure 3.1.1.3 - 2016 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity[1] (MW)	Percentage (%)
Coal	4,372	20.7%
Nuclear	3,349	15.9%
Natural Gas	7,878	37.3%
Pumped Storage	1,808	8.6%
Oil	1,833	8.7%
Renewable	590	2.8%
NUG - Coal	627	3.0%
NUG - Natural Gas Turbine	605	2.9%
NUG - Solar	45	0.2%
NUG Contracted	1,277	6.1%
Company Owned	19,829	93.9%
Company Owned and NUG Contracted	21,107	100.0%
Purchases	-	0.0%
Total	21,107	100.0%

Note: 1) Represents firm capacity towards reserve margin.

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that customers in the Company's service area receive the benefit from all resources in the PJM power pool regardless of whether the source of electricity is Company-owned, contracted, or third-party units. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 3.1.1.4 and 3.1.1.5 provide the Company's 2015 actual capacity and energy mix.

Figure 3.1.1.4 - 2015 Actual Capacity Mix

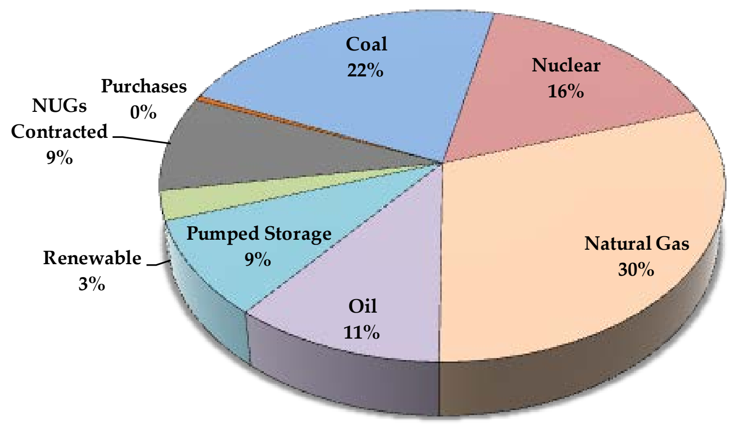
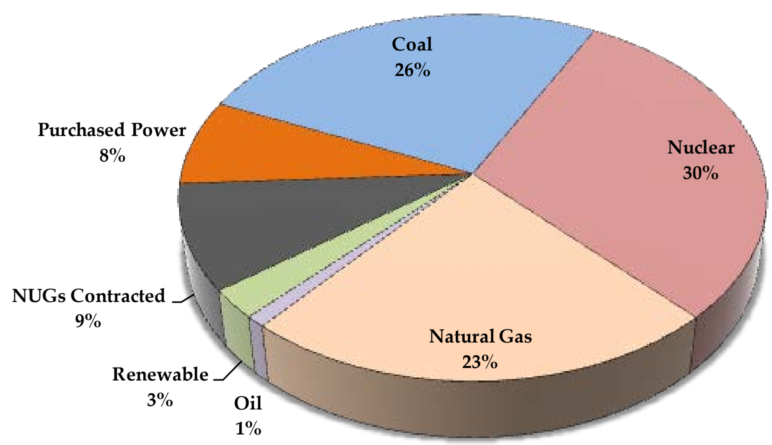


Figure 3.1.1.5 - 2015 Actual Energy Mix



Note: Pumped storage is not shown because it is net negative to the Company's energy mix.

Appendices 3A, 3C, 3D, and 3E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Additionally, Appendix 3F provides a summary of the existing capacity, by fuel class, and NUGs. Appendices 3G and 3H provide energy generation by type as well as the system output mix. Appendix 3B provides a listing of other generation units including NUGs, behind-the-meter generation ("BTMG"), and customer-owned generation units.

3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates 590 MW of renewable resources, including approximately 236 MW of biomass generating facilities. The Virginia City Hybrid Energy Center ("VCHEC") (610 MW) is expected to consume renewable biomass fuel of up to 5.5% (34 MW) in 2016 and gradually increase that level to 10% (61 MW) by 2021. The Company also owns and operates four hydro facilities: Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95 MW), Cushaw Hydro Station (2 MW), and North Anna Hydro Station (1 MW). Additionally, the Company completed the first installations of its SPP in 2014.

Renewable Energy Rates and Programs

The Company has implemented various rates and programs to increase the availability of renewable options, as summarized in Figure 3.1.2.1.

Figure 3.1.2.1 - Renewable Rates & Programs

Renewable	Supplier			Customer Group				Size Limitations	
	Company-Owned	Participant-Owned	Third-Party Owned	Residential	Small Commercial	Large Commercial	Industrial	Individual	Aggregate
Solar Partnership Program	X	-	-	-	X	X	X	500 kW – 2 MW	30 MW
Solar Purchase Program	-	X	-	X	X	-	-	Res: ≤20 kW Non-Res: ≤50 kW	3 MW
Green Power Program	-	-	X	X	X	X	X	None	None
Rate Schedule RG	-	-	X	-	-	X	X	1 million kWh/yr Min 24 million kWh/yr Max	240 million kWh/yr or 100 Customers
Third-Party PPA Pilot	-	-	X	X	X	X	X	1 kW - 1 MW	50 MW
Net Metering	-	X	-	X	X	X	X	Res: 20 kW Non-Res: 1 MW	1% of Adjusted Peak Load for Prior Year
Agricultural Net Metering	-	X	-	-	X	X	X	≤500 kW	Within Net Metering Cap

Note: Eligibility and participation subject to individual program parameters.

Solar Partnership Program

The Solar Partnership Program (or SPP) is a demonstration program in which the Company is authorized to construct and operate up to 30 MW (DC) of Company-owned solar DG facilities on leased commercial and industrial customer property and in community settings. This is intended as a five-year demonstration program to study the benefits and impacts of solar DG on targeted distribution circuits. Current installed capacity of the program is 4.0 MW. More information can be found on the SCC website under Case No. PUE-2011-00117 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/solar-partnership-program.

Solar Purchase Program

The Solar Purchase Program facilitates customer-owned solar DG as an alternative to net metering. Under this program, the Company purchases energy output, including all environmental attributes and associated renewable energy certificates ("RECs"), from participants at a premium rate under Rate Schedule SP, a voluntary experimental rate, for a period of five years. The Company's Green Power Program® directly supports the Solar Purchase Program through the purchase and retirement of produced solar RECs. There are approximately 100 participants with an installed capacity of 1.3

MW. More information can be found on the SCC website under Case No. PUE-2012-00064 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/solar-purchase-program.

Green Power Program®

The Company's Green Power Program® allows customers to promote renewable energy by purchasing, through the Company, RECs in discrete blocks equal to 100% of their usage or a portion of their usage. The Company purchases and retires RECs on behalf of participants. There are approximately 26,500 customers participating in this program. More information can be found on the SCC website under Case No. PUE-2008-00044 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/dominion-green-power.

Rate Schedule RG

Rate Schedule RG provides qualifying large non-residential customers in Virginia with the option to meet a greater portion of their energy requirements with renewable energy. Eligible customers sign a contract for the Company to purchase additional amounts of renewable energy from a third party as determined by the customer. More information can be found on the SCC website under Case No. PUE-2012-00142 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/schedule-rg.

Renewable Energy (Third-Party PPA) Pilot

The SCC's Renewable Energy Pilot Program allows qualified customers to enter into a Power Purchase Agreement ("PPA") with a third-party renewable energy supplier. The energy supplied must come from a wind or solar generator located on the customer's premise. Eight customers have provided notices of participation in this Pilot. More information can be found on the SCC website under Case No. PUE-2013-00045 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/renewable-energy-pilot-program.

Net Metering

Net Metering allows for eligible customer generators producing renewable generation to offset their own electricity usage consistent with Va. Code § 56-594 and SCC regulations governing net metering in the Virginia Administrative Code (20 VAC 5-315-10 *et seq*.) and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/traditional-net-metering. There are approximately 1,700 net metering customer-generators with a total installed capacity of approximately 12.8 MW.

Agricultural Net Metering

Agricultural Net Metering allows agricultural customers to net meter across multiple accounts on contiguous property. More information can be found on the SCC website under Case No. PUE-2014-00003 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/agricultural-net-metering.

3.1.3 CHANGES TO EXISTING GENERATION

The Company is fully committed to meeting its customers' energy needs in a manner consistent with a clean environment and supports the establishment of a comprehensive national energy and environmental policy that balances the country's needs for reliable and affordable energy with reasonable minimization of environmental impacts. Cognizant of the effective and anticipated EPA regulations concerning air, water, and solid waste constituents, and particularly the stay of the EPA's CPP regarding CO_2 emissions from existing electric generating units (see Figure 3.1.3.1), the Company continuously evaluates various options with respect to its existing fleet.

As a result, the Company has a balanced portfolio of generating units, including low-emissions nuclear, highly-efficient and clean-burning natural gas, and hydro that has a lower carbon intensity compared to the generation fleet of most other integrated energy companies in the country. As to the Company's coal generators, the majority of those generators are equipped with SO_2 and NO_x controls; however, the remaining small coal-fired units are without sufficient emission controls to comply with effective and anticipated regulatory requirements. The Company's coal-fired units at the Chesterfield, Mt. Storm, Clover, Mecklenburg and VCHEC facilities have flue gas desulfurization environmental controls to control SO_2 emissions. The Company's Chesterfield Units 4, 5 and 6, Mt. Storm, Clover, and VCHEC coal-fired generation units also have selective catalytic reduction ("SCR") or SNCR technology to control NO_x emissions. The Company's biomass units at Pittsylvania, Altavista, Hopewell and Southampton operate SNCRs to reduce NO_x. In addition, the Company's NGCC units at Bellemeade, Bear Garden, Gordonsville, Possum Point and Warren County have SCRs.

Uprates and Derates

Efficiency, generation output, and environmental characteristics of plants are reviewed as part of the Company's normal course of business. Many of the uprates and derates discussed in this section occur during routine maintenance cycles or are associated with standard refurbishment. However, several plant ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations.

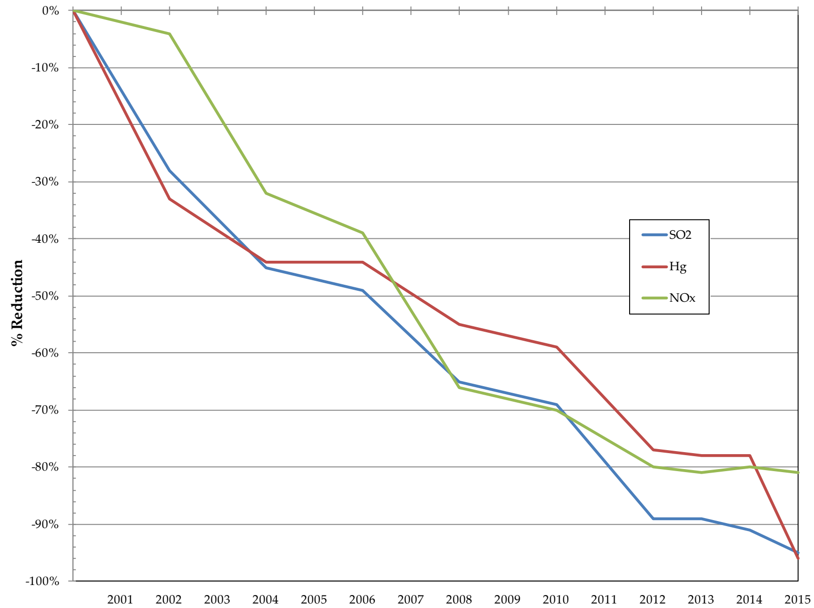
Possum Point Unit 6 is a 2x1 CC unit that went into commercial operation in July 2003. A turbine uprate was completed in the spring of 2015, which increased summer capacity from 559 MW to 573 MW.

Bear Garden Power Station ("Bear Garden") is a 2x1 CC that was completed in the summer of 2011. A turbine uprate is planned to be completed in the spring of 2017, which will increase summer capacity from 590 MW to 616 MW.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means of increasing generating capacity and improving system reliability. Appendix 3I provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

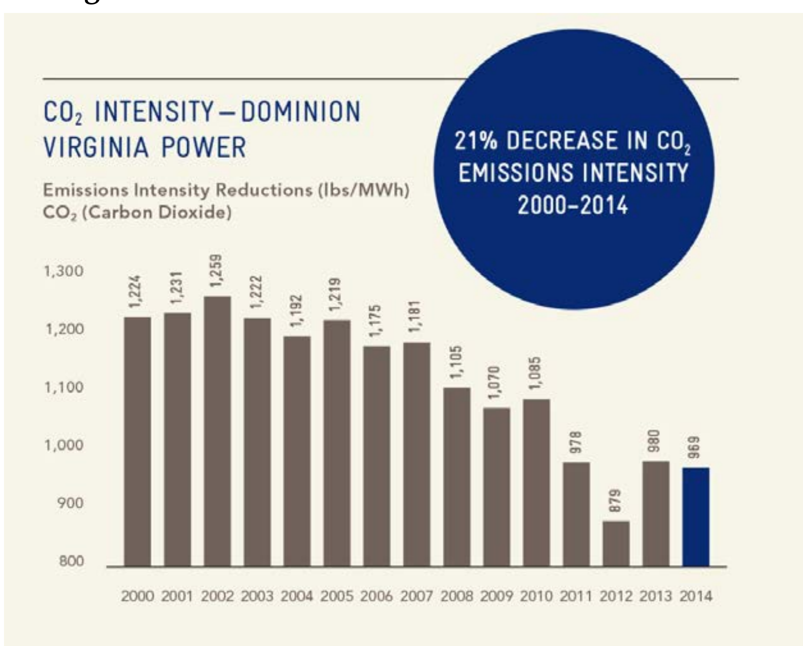
Environmental Performance
The Company has reduced emissions of SO_2, NO_x, and mercury from its generation fleet over the last decade as reflected in Figure 3.1.3.1.

Figure 3.1.3.1 – Dominion Virginia Power Emission Reductions (lbs/MWh)



Similarly, the Company has reduced emissions of greenhouse gases, including CO_2, through retiring certain at-risk units and building additional efficient and lower-emitting power generating sources. The CO_2 emission reductions from 2000 through 2014 are shown in Figure 3.1.3.2.

Figure 3.1.3.2 – CO_2 Emission Reductions 2000 - 2014



EPA Regulations

There are a significant number of final, proposed, stayed and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. As shown in Figure 3.1.3.3, these regulations are designed to regulate air, solid waste, and water constituents.

Figure 3.1.3.3 - EPA Regulations

Constituent		Key Regulation	Final Rule	Compliance
AIR	Hg/HAPS	Mercury & Air Toxics Standards (1) (MATS)	12/16/2011	4/16/2015
				4/16/2017
	SO_2	CSAPR (2)	2011	2015/2017
		SO_2 NAAQS	6/2/2010	2018
	NOx	2008 Ozone Standard (75 ppb)	5/2012	2017
		2015 Ozone Standard (70 ppb)	10/1/2015	2018 - 2019
		CSAPR (3)	2011	2015/2017
	CO_2	GHG Tailoring Rule	5/2010	2011
		EGU NSPS (New)	10/2015	Retro to 1/8/2014
		Clean Power Plan (CPP) (4)	10/2015	2022/2030 (4)
		EGU NSPS (Modified and Reconstructed)	10/2015	10/23/2015
		Federal CO_2 Program (Alternative to CPP)	Uncertain	2023
WASTE	ASH	CCR's	4/17/2015	2018 - 2020
WATER	Water 316b	316b Impingement & Entrainment (5) (6)	5/19/2014	2019
	Water Effluent	Effluent Limitation Guidelines (7)	9/30/2015	11/1/2018

Key: Constituent: Hg: Mercury; HAPS: Hazardous Air Pollutants; SO_2: Sulfur Dioxide; NOx: Nitrogen Oxide; CO_2: Carbon Dioxide; GHG: Greenhouse Gas; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;

Regulation: MATS: Mercury & Air Toxics Standards; CPP: EPA's Clean Power Plan; CSAPR: Cross-State Air Pollution Rule; SO_2 NAAQS: Sulfur Dioxide National Ambient Air Quality Standards; Ozone Std Rev PPB: Ozone Standard Review Parts per Billion; EGU NSPS: Electric Generating Units New Source Performance Standard.

Note: (1) CEC 1-4 retired in December 2014. YT 1-2 to be retired by April 16, 2017 (per provisions of the EPA Administrative Order of April 16, 2016).

(2) SO_2 allowances will be decreased by 50% in 2017. Retired units retain CSAPR allowances for four years. System is expected to have sufficient SO_2 allowances.

(3) Proposed revisions to CSAPR would reduce ozone season NOx allowances by ~55% beginning in 2017. Could have allowance shortfalls as early as 2018 if limits imposed on use of banked allowances. Retired units retain CSAPR allowances for 4 years. System is expected to have sufficient annual NO_X allowances.

(4) CPP sets interim targets (2022-2024; 2025-2027; 2028-2029) in addition to 2030 targets. CPP also sets "equivalent" statewide Intensity-Based and Mass-Based interim 2030 targets. CPP is currently stayed.

(5) Rule would not apply to Mt. Storm under the assumption that the plant's man-made lake does not qualify as a "water of the U.S."

(6) 316(b) studies will be due with discharge permit applications beginning in mid-2018. Installation of 316(b) technology requirements will be based on compliance schedules put into discharge permits.

(7) Rule does not apply to simple-cycle CTs or biomass units.

Revised Ozone National Ambient Air Quality Standards ("NAAQS")
In May 2008, the EPA revised the ozone standard from 80 ppb to 75 ppb. Subsequently, in October 2015, the EPA issued a final rule tightening the ozone standard from 75 ppb to 70 ppb. States will have until 2020 or 2021 to develop plans to address the new standard. Until then, the Company is unable to predict whether the new rules will ultimately require additional controls. However, for planning purposes, we have included additional NO_x control equipment in the form of SNCR technology on Possum Point Unit 5 as a potentially feasible control option in 2018. The need to install additional controls for either the 2008 (75 ppb) standard or the revised 2015 (70 ppb) standard will be determined by the Virginia Department of Environmental Quality ("DEQ") assessment of Reasonable Available Control Technology ("RACT") requirements under the Ozone NAAQS SIP. No other power generating units are expected to be impacted by the standards.

Cross-State Air Pollution Rule ("CSAPR")
In December 2015, the EPA published a proposed revision to CSAPR. If finalized as proposed, the revised rule will substantially reduce the CSAPR Phase II ozone season NO_x emission caps in 23 states, including Virginia, West Virginia and North Carolina, which would take effect beginning with the 2017 ozone season. The proposed reductions in state caps would in turn reduce, by approximately 55% overall, the number of allowances the Company's EGUs will receive under the CSAPR Phase II ozone season NO_x program. In addition, the EPA is proposing to discount the use of banked Phase I allowances for compliance in Phase II by applying either a 2:1 or 4:1 surrender ratio. At this time, the Company has not planned for any additional NO_x controls to be installed on any units.

Coal Ash Regulations
In April 2015, the EPA's final rule regulating the management of coal combustion residuals ("CCRs") stored in impoundments (ash ponds) and landfills was published in the Federal Register. This final rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store CCRs. The Company currently owns inactive ash ponds, existing ash ponds, and CCR landfills subject to the CCR final rule at eight different facilities. The final rule required the Company to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary. The Company is in the process of complying with all these requirements.

Clean Water Intake Regulations (i.e., Clean Water Act, Section 316(b))
In October 2014, final regulations became effective under Section 316(b) of the Clean Water Act ("CWA"), which govern existing facilities that employ a cooling water intake structure and have flow levels exceeding a minimum threshold, became effective. The rule establishes a national standard for impingement based on seven compliance options. The EPA has delegated entrainment technology decisions to state environmental regulators. State environmental regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost/benefit test and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day. The Company has 11 facilities that may be subject to the regulations, and anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling

systems. Currently, the Company is evaluating the need or potential for entrainment controls under the final regulations as these decisions will be made on a case-by-case basis by the state regulatory agency after a thorough review of detailed biological, technology, cost and benefit studies. Any new technology requirements will likely be incorporated in discharge permits issued after 2018, and will be installed in accordance with schedules established in those permits. The costs for these additional control technologies could be significant.

Clean Power Plan Overview

On August 3, 2015, the EPA promulgated the final CPP rule to regulate CO_2 emissions from existing power plants under Section 111(d) of the Clean Air Act. The EPA has projected the full implementation of the final rule across all affected states will achieve a 32% reduction in nationwide power plant CO_2 emissions from 2005 levels by 2030. The CPP is designed to start in 2022, with an eight-year interim period, and final targets in 2030. Under the CPP (prior to the Supreme Court stay), states were required to submit initial SIPs by September 6, 2016, but could request an extension to submit final plans by September 6, 2018. Further, state progress reports were also required by the CPP on September 6, 2017. The final rule was published in the Federal Register on October 23, 2015.

In addition, on October 23, 2015, the EPA published a proposed Federal Plan and proposed model trading rules for both Intensity-Based and Mass-Based programs that the EPA will implement in states that fail to submit plans. The EPA was expected to finalize the FIP and model trading rules by summer 2016. The impact of the Supreme Court stay of the CPP on the EPA's finalization of these proposed rules, the State Plan submittal deadlines and the interim and final CPP compliance deadlines is uncertain at this time.

In the final CPP rule, an affected source is any fossil fuel-fired electric steam generating unit (e.g., utility boiler, integrated-gasification combined-cycle ("IGCC")), or NGCC that was in operation or under construction as of January 8, 2014. Simple-cycle CTs are excluded from the definition of affected units. Therefore, all Company owned fossil steam and NGCC units are considered affected units up through and including the Brunswick Power Station, which has commenced operations in 2016.

The final rule requires each state with affected EGUs to develop and implement plans that ensure that the affected EGUs in their states either individually, together, or in combination with other measures to achieve the interim and final Intensity-Based targets or Mass-Based targets. As identified in Chapter 1, each state with affected EGUs will have six options for compliance under the CPP. Three options are Intensity-Based and three options are Mass-Based. The three Intensity-Based options are:

- Intensity-Based Dual Rate Program – An Intensity-Based CO_2 program that requires each existing:
  - steam unit to achieve an intensity target of 1,305 lbs of CO_2 per MWh by 2030, and beyond; and
  - NGCC units to achieve intensity targets of 771 lbs of CO_2 per MWh by 2030, and beyond.

These standards are consistent for any state that elects an Intensity-Based Dual Rate Program;

- Intensity-Based State Average Program – An Intensity-Based CO_2 program that requires all affected existing generation units to achieve a portfolio average intensity target by 2030, and beyond. In Virginia that average intensity is 934 lbs of CO_2 per MWh by 2030 and beyond. The 2030 and beyond targets for West Virginia and North Carolina are 1,305 lbs of CO_2 per MWh and 1,136 lbs of CO_2 per MWh, respectively; and
- Unique State Intensity-Based Program – A unique state Intensity-Based program designed so that the ultimate state level intensity target does not exceed those targets described in the Intensity-Based targets set forth in 1 and 2 above.

The three options that are Mass-Based are:

- Mass-Based Emissions Cap (existing units only) Program – A Mass-Based program that limits the total CO_2 emissions from the existing fleet of affected generating units. In Virginia, this limit is 27,433,111 short tons CO_2 (per year) beginning in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,325,342 short tons of CO_2 and 51,266,234 short tons of CO_2, respectively;
- Mass-Based Emissions Cap (existing and new units) Program – A Mass-Based program that limits the total CO_2 emissions from both the existing fleet of generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of CO_2 (per year) beginning in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,857,307 short tons of CO_2 and 51,876,856 short tons of CO_2, respectively; and
- Unique State Mass-Based Program – A unique state Mass-Based approach.

Intensity-Based Programs

Under each of the Intensity-Based options, states can design plans to encourage EGUs to reduce CO_2 emissions through actions such as heat rate improvements, fuel switching, environmental dispatch, retirements, or a state may implement an intra-state trading program to enable EGUs to generate and/or procure ERCs. ERCs are measured in MWhs and can be generated by: (i) affected units operating below the performance standard; (ii) generation of zero emitting energy (including new nuclear generation); and (iii) demand-side and supply-side energy efficiency. To demonstrate compliance, an affected EGU (or portfolio of affected EGUs) operating above the emissions performance rate would procure (or generate) ERCs and add those ERCs to the denominator in its rate calculation resulting in a lower calculated rate. For example, assume that an affected NGCC operating at 1,000 lbs CO_2/MWh and needs to comply with a target rate of 771 lbs CO_2/MWh. To achieve compliance, the NGCC needs to procure the following amount of ERCs for each MWh that the NGCC generates in a given compliance period:

$$(1{,}000 \text{ lbs } CO_2 \text{ per MWh} \div 771 \text{ lbs. } CO_2 \text{ per MWh}) - 1 = 0.297 \text{ ERCs}$$

In states that adopt an Intensity-Based Dual Rate Program, ERCs can also be generated by affected NGCC units following an EPA formula that encourages efficient gas generation. These ERCs, called

Gas-Shift ERCs, are available for compliance use by fossil steam generating (coal, gas, and oil) units only. This is a valuable option for the Company and its customers given that the Company currently has a fuel diverse fleet of generation assets that includes many large NGCCs. For example, affected Company owned NGCC generation units could produce Gas-Shift ERCs that could then be used by the Company to help meet the compliance obligations of the Company's coal fleet or other steam units located within the state.

The role of ERCs in Intensity-Based CPP compliance is significant. In addition to the Gas-Shift ERCs described above, the amount of ERCs that may be available to the Company and its customers corresponds to the amount of renewable generation available to the Company. This includes self-build renewable generation, along with renewable generation purchases from within the state or potentially outside the state. ERCs can also be earned by the amount of new nuclear generation including uprates to existing nuclear facilities. This ERC supply aspect should be compared to Mass-Based programs that have hard limits on the level of CO_2 that may be emitted in a given time period. Given the societal and industry movement towards renewable energy, it is not unrealistic to anticipate that the level of renewable generation will increase over time thus increasing the available supply of ERCs. Conversely, under provisions of the CPP, the supply of CO_2 allowances under Mass-Based programs will stay fixed even though load increases. This expected supply dynamic increases the options available to the Company and its customers under an Intensity-Based program which will help keep rates low, and help maintain a level of fuel price mitigation for the Company's customers via fuel diversity.

Mass-Based Programs

Mass-Based programs are designed to collectively cap total CO_2 emissions from all affected EGUs during any given compliance period. For each ton of CO_2 emitted, the emitting entity must surrender a CO_2 allowance. These allowances could be directly allocated to affected facilities or other entities or can be auctioned (for sale) by a state. The Company strongly discourages the concept of auctioning allowances in the Commonwealth of Virginia because of the significant adverse impact to electric rates. This action could prove to be punitive to the Company's customers in that those customers would have to pay for both new generation units designed to meet the CPP and CO_2 allowances required to operate existing affected generation units.

Under a Mass-Based program that would allocate allowances, states can also hold back a selected level of CO_2 allowances, known as set-aside allowances. States can use these set-aside allowances as a mechanism to create incentives for the development of non-emitting resources (including new nuclear), DSM/energy efficiency ("EE") programs, or other clean energy options. An important point to stress is that set-aside allowances are not newly created allowances that add to the total supply of allowances. Rather, set-aside allowances are subtracted from the total allowance supply for any given state. This translates into fewer allowances available to affected EGUs and unpredictable market valuation of allowances.

Mass-Based programs must also account for an EPA concept called "leakage." The CPP defines leakage as emissions that would not otherwise occur, but result from the shift in generation from existing affected fossil generation to new fossil generation units that are considered regulated in accordance with Section 111(b) of the Clean Air Act and are not subject to the CPP. Under the current CPP model trading rules, a state implementing a Mass-Based compliance program can choose one of three options to address such leakage. Those options are:

- Include existing affected generation units and new generation units in the Mass-Based program: As stated in Chapter 1 and as shown in Chapter 6, this option would be difficult to achieve and costly for Virginia given its generation capacity position coupled with Virginia's expected electric energy demand growth. Chapter 6 includes Plan E: Mass Emission Cap (existing and new units) that identifies an expansion plan that would be necessary in order to meet the CO_2 emission standards for Virginia. Not only is this Plan the most costly of the Plans evaluated in the 2016 Plan filing, it would require the Company to retire its entire coal generation fleet in Virginia, including VCHEC in 2029. This would likely cause significant economic harm to Virginia and also substantially reduce the fuel diversity within the Company's generation fleet leaving customers vulnerable to natural gas market price volatility;
- Use an allowance allocation method that counteracts leakage: Under the current CPP model trading rules, the state must populate a set-aside portion of allowances to existing affected NGCC units to encourage NGCC generation over steam generation and when a unit retires those allocated allowances must be transferred to the renewable set-aside allowance portion. The theory behind this approach is that it will establish an incentive for operation of existing affected NGCC units in lieu of new NGCC generation not subject to the CPP, but still regulated under the EPA's New Source Performance Standards ("NSPS") under CAA Section 111(b), and will financially incent new renewable to get built. Again, these set-aside allowances will be subtracted from the overall CO_2 allowance supply; or
- A unique method that demonstrates to the EPA that leakage is not likely to occur.

Interstate Trading and Banking of ERCs and CO_2 Allowances

Overall, the Company favors CPP programs that promote trading of ERCs and/or CO_2 allowances. This is a key aspect of any program because trading provides a clear market price signal which is the most efficient means of emission mitigation. Also, trading markets offer flexibility in the event of years where a higher level of ERCs or CO_2 allowances are required due to higher than expected fossil generation resulting from weather, or outages of low- or non-emitting generation resources, or both. Through the CPP and the associated model trading rules, the EPA has offered a framework that defines "trading-ready" programs. In other words, programs that will likely be approved by EPA and eligible to conduct interstate exchange of ERCs or CO_2 allowances with other trading-ready states. Given that the definition of "trading-ready" programs has already been established by the EPA, it is highly likely that most states will adopt this framework rather than seeking approval of a program that runs the risk of either being rejected by the EPA, or approved as a unique program that has no other like programs with which to trade. Therefore, the Company expects that "trading-ready" programs offered in the CPP and the associated EPA model rule will be adopted by most states and offer the best alternative to promote robust and liquid trading markets.

The 2015 Plan Final Order required the Company to examine the cost benefits of trading emission allowances or emission rate credits, or acquiring renewable resources from inside or outside of Virginia. As stated above, the ability to trade CO_2 allowances or ERCs, or acquire renewable generation offers clear price signals that enable more accurate economic decisions but most importantly, offers the Company and its customers flexibility in compliance with the CPP. This flexibility (or optionality) is difficult to quantify at this time in an inherently static cost benefit analysis especially since these markets have yet to develop. Once markets have developed, however, the Company will utilize these markets in making operational, tactical or strategic generation portfolio decisions to assure reliable electric service to customers at the lowest reasonable cost. Nevertheless, utilizing the information included in this 2016 Plan, the Company's high level estimate of the value of trading CO_2 allowances or ERCs is estimated to range between $0 and $25 million per year. This range could be even greater if the price of CO_2 allowances or ERCs is higher than forecasted by ICF and used in this 2016 Plan.

In general, states that adopt the standard Mass-Based programs can trade CO_2 allowances with other states that have adopted Mass-Based programs. Under the CPP, the EPA considers Mass-Based programs to be "trading ready." This, however, is not the case with Intensity-Based programs. EPA maintains that states that adopt an Intensity-Based program may trade ERCs with other states that have "similar" Intensity-Based programs. The final assessment of what state programs are "similar" is the responsibility of the EPA and standards for such determination are uncertain with one exception. That exception is for states adopting a Dual Rate program consistent with the EPA's proposed model rule. Dual rate programs that are consistent with the Intensity-Based model rule are considered by the EPA to be "trading ready." The Company maintains that for states that elect to pursue Intensity-Based programs, it is likely that those states will elect the Intensity-Based Dual Rate Program option in order to mitigate the uncertainty associated with meeting the "similarity" standard mentioned above. Given this likely outcome coupled with the advantages of an Intensity-Based program mentioned above, and given the Company's understanding of the EPA model trading rules as currently proposed, the Company believes that the adoption of an Intensity-Based Dual Rate approach offers the most cost-effective and flexible option for implementing the CPP in the Commonwealth of Virginia.

Regarding banking, the CPP allows for un-constrained banking of ERCs and/or CO_2 allowances. In other words there is no expiration period associated with banked ERCs and/or CO_2 allowances.

Early Action/Clean Energy Incentive Program

Within the CPP, the EPA has included a program entitled the Clean Energy Incentive Program ("CEIP"). The CEIP is designed to provide incentives for early development of new renewable generation and DSM/EE programs before the start of the CPP's mandatory reductions period in 2022. More specifically, projects that fit these categories must start construction (in the case of renewable generation), or commence operation (in the case of DSM/EE) after the final State Plan is submitted. Further, credits will be awarded to eligible projects for energy (MWhs) they either generate (renewables) or save (reduce demand) in low-income communities (for DSM/EE) during 2020 or 2021.

Under the CEIP, the state will issue early action ERCs (in an Intensity-Based program) or allowances (in a Mass-Based program) and EPA will award matching ERCs or allowances from a nationwide pool totaling 300 million tons of CO_2. Approximately 4 million tons have been set aside for Virginia. Eligible renewable projects will be awarded CEIP credits on a 1:1 basis (for every 2 MWh generated, the state will issue 1 early action ERC (or allowance) to the project and EPA will issue a matching

credit (ERC or allowance)). Energy efficiency projects will be granted CEIP credits on a 2:1 basis (for every 2 MWh, the state will issue 2 credits and the EPA will issue a matching 2 credits).
To participate in the CEIP, the EPA is requiring states to implement offsetting adjustments to electric generating unit obligations imposed during the interim (2022 - 2029) period in an amount equivalent to the credits issued by the state under the CEIP. The offsetting requirement does not apply to the matching EPA credits.

The preamble to the final rule explains that a state with a Mass-Based program can satisfy the offsetting requirement by setting aside a portion of its interim period allowance budget and use that set-aside pool for purposes of awarding CEIP allowance credits. For Intensity-Based programs, the EPA asserts that a state could adjust the stringency of the emission rate targets during the interim compliance period to account for the issuance of CEIP ERCs or could retire an amount of ERCs during the interim compliance period that is equivalent to the amount of CEIP ERCs granted.

Although the CPP is final, the EPA has not yet finalized the specific provisions of the CEIP. Given the Supreme Court stay of the CPP, final details of the design, implementation and timelines related to the CEIP remain uncertain at this time.

Under the proposed provisions of the CEIP, a portion of the 400 MW of Virginia utility-scale solar generation the Company intends to phase in from 2016 - 2020 should be eligible for incentives. The Company does not anticipate any ERCs or allowances to be granted under the CEIP from its current set of approved low-income programs in Virginia because the program was approved for a three year period in 2015. The Company would have to seek approval of additional low-income programs that may allow for additional participation beyond the approval dates. However, as of the 2016 Plan cycle, the Company has not developed or analyzed any new low-income programs during the CEIP window identified in the CPP.

3.1.4 GENERATION RETIREMENTS/BLACKSTART

Retirements

Based on the current and anticipated environmental regulations along with current market conditions, the 2016 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. Yorktown Units 1 (159 MW) and 2 (164 MW) are scheduled for retirement in 2017. On April 16, 2016, the EPA granted permission through an Administrative Order to operate the Yorktown coal-fired units through April 15, 2017 under certain limitations consistent with the federal Mercury and Air Toxics Standards ("MATS") rule.

Currently under evaluation is the potential retirement of Yorktown Unit 3, 790 MW of oil-fired generation, to be retired by 2022 (included in all CPP-Compliant Alternative Plans). Also under evaluation are the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement by 2022 (Plans B, C, D, and E). Plan E: Mass Emissions Cap (existing and new units) models the potential retirement of the entire Company-owned Virginia coal fleet, including all coal generation in Virginia by 2022, except for VCHEC, which retires by 2029. Appendix 3J lists the planned retirements included in Plan B: Intensity Dual Rate.

Blackstart

Blackstart generators are generating units that are able to start without an outside electrical supply or are able to remain operating at reduced levels when automatically disconnected from the grid. The North American Electric Reliability Corporation ("NERC") Reliability Standard EOP-005 requires the RTO to have a plan that allows for restoring its system following a complete shutdown (i.e., blackout). As the RTO, PJM performs an analysis to verify all requirements are met and coordinates this analysis with the Company in its role as the Transmission Owner. The Company and other PJM members have and continue to work with PJM to implement a RTO-wide strategy for procuring blackstart resources. This strategy ensures a resilient and robust ability to meet blackstart and restoration requirements. It is described in detail in Section 10 of PJM Manual 14D – Generator Operational Requirements. PJM will issue an RTO-wide Request for Proposals ("RFP") for blackstart generation every five years, which will be open to all existing and potential new blackstart units on a voluntary basis. Resources are selected based upon the individual needs of each transmission zone. The first five-year selection process was initiated in 2013 and resulted in blackstart solutions totaling 286 MW in the DOM Zone. Two solutions became effective on June 1, 2015. The first was for 50 MW and the second was for 85 MW; and another solution (151 MW) is scheduled for final acceptance on June 30, 2016. Blackstart solutions from the subsequent five-year selection processes will be effective on the following April 1. For incremental changes in resource needs or availability that may arise between the five-year solicitations, the strategy includes an incremental RFP process.

3.1.5 GENERATION UNDER CONSTRUCTION

Pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686), the SCC granted the Company in November 2012 a "blanket" certificate of public convenience and necessity ("CPCN") to construct and operate up to 24 MW alternating current ("AC") (30 MW DC) of Company-owned solar DG facilities at selected large commercial and industrial customer locations dispersed throughout its Virginia service territory by 2016 (SPP). To date, the Company has installed 2 MW (nameplate) of new solar generation at various customer locations throughout its service territory. Approximately 7 MW (nameplate) of new solar under the SPP are at various stages of development.

The Company's Greensville Power Station (1,585 MW CC unit) CPCN was approved by the SCC on March 29, 2016. It is expected to be online by 2019.

Figure 3.1.5.1 and Appendix 3K provide a summary of the generation under construction along with the forecasted in-service date and summer/winter capacity.

Figure 3.1.5.1 - Generation under Construction

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)		
					Nameplate	Summer	Winter
2017	Solar Partnership Program	VA	Solar	Intermittent	7	2	2
2019	Greensville County Power Station	VA	Natural Gas	Intermediate/Baseload	1,585	1,585	1,710

Note: 1) Commercial Operation Date.

3.1.6 NON-UTILITY GENERATION

A portion of the Company's load and energy requirements is supplemented with contracted NUG units and market purchases. The Company has existing contracts with fossil-burning and renewable NUGs for capacity of 1,277 MW. These NUGs are considered firm generating capacity resources and are included in the 2016 Plan.

Each of the NUG facilities listed as a capacity resource in Appendix 3B, including the solar NUGs, is under contract to supply capacity and energy to the Company. NUG units are obligated to provide firm generating capacity and energy at the contracted terms during the life of the contract. The firm generating capacity from NUGs is included as a resource in meeting the reserve requirements.

For modeling purposes, the Company assumed that its NUG capacity will be available as a firm generating capacity resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned/sponsored supply- or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

Additionally, the Company is currently working with a number of potential solar qualifying facilities. The Short-Term Action Plan and all of the CPP-Compliant Alternative Plans include a total of 600 MW (nameplate) of North Carolina solar NUGs by 2017, which includes 308 MW of PPAs that have been signed as of May 2015. The Company is continually evaluating NUG opportunities as they arise to determine if they are beneficial to customers.

3.1.7 WHOLESALE & PURCHASED POWER

Wholesale Power Sales

The Company currently provides full requirements wholesale power sales to three entities, which are included in the Company's load forecast. These entities are Craig Botetourt Electric Cooperative, the Virginia Municipal Electric Association No.1, and the Town of Windsor in North Carolina. Additionally, the Company has partial requirements contracts to supply the supplemental power needs of the North Carolina Electric Membership Cooperative. Appendix 3L provides a listing of wholesale power sales contracts with parties whom the Company has either committed, or expects to sell power during the Planning Period.

Purchased Power

Except for the NUG contracts discussed in Section 3.1.6, the Company does not have any bilateral contractual obligations with wholesale power suppliers or power marketers. As a member of PJM, the Company has the option to buy capacity through the Reliability Pricing Model ("RPM") auction ("RPM auction") process to satisfy its RPM requirements. The Company has procured its capacity obligation from the RPM market through May 31, 2019. The method chosen by neighboring states to meet EPA's proposed CPP targets in their respective states could adversely affect the future price and/or availability of purchased power should a large number of steam generation units (i.e., coal and oil) elect to retire.

Behind-the-Meter Generation

BTMG occurs on the customer's side of the meter. The Company purchases all output from the customer and services all of the customer's capacity and energy requirements. The unit descriptions are provided in Appendix 3B.

3.1.8 REQUEST FOR PROPOSAL

The Company issued an RFP on November 3, 2014, for up to approximately 1,600 MW of new or existing intermediate or baseload dispatchable generation located within the DOM Zone, or designated areas within an adjacent zone of PJM. The RFP requested PPAs with a term of 10 to 20 years, commencing in the 2019/2020 timeframe. Multiple proposals were received and evaluated. The Company's self-build CC in Greensville County provided superior customer benefits compared to all other options. The Greensville County CPCN was approved by the SCC on March 29, 2016.

The Company issued an RFP on July 22, 2015 seeking third party bids for solar facilities between 1 and 20 MW of capacity that are scheduled to be on-line by 2017. The proposals could be for either PPAs for 1 to 20 MW, or for the purchase of development projects between 10 and 20 MW. The Company also would have considered proposals for greater than 20 MW if the bidder could demonstrate the ability to complete the PJM interconnection process on schedule to meet the 2016-2017 in service date. Multiple proposals were received and evaluated. As a result of the RFP, the Company signed 2 PPAs for 40 MW and chose the Scott Solar development project along with two Company self-builds at Whitehouse and Woodland.

3.2 DEMAND-SIDE RESOURCES

The Commonwealth of Virginia has a public policy goal set forth in the 2007 Electric Utility Reregulation Act of reducing the consumption of electric energy by retail customers by 2022 by an amount equal to 10% of the amount of electric energy consumed by retail customers in Virginia in 2006. The Company has expressed its commitment to helping Virginia reach this goal through bringing applications for the approval of cost-effective DSM programs to the SCC. Related to and consistent with the goal, DSM programs are an important part of the Company's portfolio available to meet customers' growing need for electricity along with supply-side resources.

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. Demand-side resources encourage the more efficient use of existing resources and delay or eliminate the need for new supply-side infrastructure. The Company's DSM programs are designed to provide customers the opportunity to manage or reduce their electricity usage.

In this 2016 Plan, four categories of DSM programs are addressed: i) those approved by the SCC and NCUC; ii) those filed with the SCC for approval, iii) those programs that are under consideration but have not been evaluated and may be potential DSM resources; and iv) those programs currently rejected from further consideration at this time. The Company's Programs have been designed and evaluated using a system-level analysis. For reference purposes, Figure 3.2.1 provides a graphical representation of the approved, proposed, future, and rejected programs described in Chapters 3 and 5.

Figure 3.2.1 - DSM Tariffs & Programs

Tariff	Status (VA/NC)
Standby Generator Tariff	Approved/Approved
Curtailable Service Tariff	
Program	**Status (VA/NC)**
Air Conditioner Cycling Program	Approved/Approved
Residential Low Income Program	Completed/Completed
Residential Lighting Program	
Commercial Lighting Program	Closed/Closed
Commercial HVAC Upgrade	
Non-Residential Distributed Generation Program	Approved/Rejected
Non-Residential Energy Audit Program	Approved/Approved
Non-Residential Duct Testing and Sealing Program	
Residential Bundle Program	
Residential Home Energy Check-Up Program	
Residential Duct Sealing Program	
Residential Heat Pump Tune Up Program	
Residential Heat Pump Upgrade Program	
Non-Residential Window Film Program	
Non-Residential Lighting Systems & Controls Program	
Non-Residential Heating and Cooling Efficiency Program	
Income and Age Qualifying Home Improvement Program	
Residential Appliance Recycling Program	Approved/No Plans
Residential Programmable Thermostat Program	Rejected/No Plans
Small Business Improvement Program	Approved/Under Evaluation
Home Energy Assessment	Under Consideration/ Under Consideration
Prescriptive Program for Non-Residential Customers	
Voltage Conservation	
Non-Residential HVAC Tune-Up Program	Rejected and Currently Not Under Consideration
Energy Management System Program	
ENERGY STAR® New Homes Program	
Geo-Thermal Heat Pump Program	
Home Energy Comparison Program	
Home Performance with ENERGY STAR® Program	
In-Home Energy Display Program	
Premium Efficiency Motors Program	
Programmable Thermostat Program	
Residential Refrigerator Turn-In Program	
Residential Solar Water Heating Program	
Residential Water Heater Cycling Program	
Residential Comprehensive Energy Audit Program	
Residential Radiant Barrier Program	
Residential Lighting (Phase II) Program	
Non-Residential Refrigeration Program	
Cool Roof Program	
Non-Residential Data Centers Program	
Non-Residential Re-commissioning	
Non-Residential Curtailable Service Program	
Non-Residential Custom Incentive	
Enhanced Air Conditioner Direct Load Control Program	
Residential Controllable Thermostat Program	
Residential Retail LED Lighting Program	
Residential New Homes Program	

3.2.1 DSM PROGRAM DEFINITIONS

For purposes of its DSM programs in Virginia, the Company applies the Virginia definitions set forth in Va. Code § 56-576, as provided below.

- **Demand Response** – Measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.
- **Energy Efficiency Program** – A program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome. Energy efficiency programs may include, but are not limited to, i) programs that result in improvements in lighting design, heating, ventilation, and air conditioning systems, appliances, building envelopes, and industrial and commercial processes; ii) measures, such as, but not limited to, the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems; and (iii) customer engagement programs that result in measurable and verifiable energy savings that lead to efficient use patterns and practices. Energy efficiency programs include demand response, combined heat and power and waste heat recovery, curtailment, or other programs that are designed to reduce electricity consumption, so long as they reduce the total amount of electricity that is required for the same process or activity. Utilities are authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in Chapter 23 of Title 56 establishes a requirement that an energy efficiency program be implemented on a customer's premises and be connected to a customer's wiring on the customer's side of the inter-connection without the customer's expressed consent.
- **Peak-Shaving** – Measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

For purposes of its DSM programs in North Carolina, the Company applies the definitions set forth in NCGS § 62-133.8 (a) (2) and (4) for DSM and energy efficiency measures as defined below.

- **Demand-Side Management**: Activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to non-peak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.
- **Energy Efficiency Measure**: Equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. Energy efficiency measure includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. It does not include DSM.

3.2.2 CURRENT DSM TARIFFS

The Company modeled existing DSM pricing tariffs over the Study Period, based on historical data from the Company's Customer Information System ("CIS"). These projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No active DSM pricing tariffs have been discontinued since the Company's 2015 Plan.

STANDBY GENERATION

Program Type: Energy Efficiency - Demand Response

Target Class: Commercial & Industrial

Participants: 5 customers on Standby Generation in Virginia

Capacity Available: See Figure 3.2.2.1

The Company currently offers one DSM pricing tariff, the Standby Generation ("SG") rate schedule, in Virginia. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed.

The SG rate schedule provides a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or average capacity generated during a billing month when SG is requested.

During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator. Figure 3.2.2.1 below provides estimated load response data for summer/winter 2015. Additional jurisdictional rate schedule information is available on the Company's website at www.dom.com.

Figure 3.2.2.1 - Estimated Load Response Data

Tariff	Summer 2015		Winter 2015	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	16	2	12	2

3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

Pilots

The SCC approved nine pilot DSM programs in Case No. PUE-2007-00089, all of which have ended. The Company has received SCC approval for implementation of additional pilots and they are described below.

Dynamic Pricing Tariffs Pilot

State: Virginia

Target Class: Residential and Non-Residential

Pilot Type: Peak-Shaving

Pilot Duration: Enrollment closed on November 30, 2014
Pilot concludes July 31, 2017

Description:

On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was in response to the SCC's directive to the Company to establish a pilot program under which eligible customers volunteering to participate would be provided the ability to purchase electricity from the Company at dynamic rates.

A dynamic pricing schedule allows the Company to apply different prices as system production costs change. The basic premise is that if customers are willing to modify behavior and use less electricity during high price periods, they will have the opportunity to save money, and the Company in turn will be able to reduce the amount of energy it would otherwise have to generate or purchase during peak periods.

Specifically, the Pilot is limited to 3,000 participants consisting of up to 2,000 residential customers taking service under experimental dynamic pricing tariff DP-R and 1,000 commercial/general customers taking service under dynamic pricing tariffs DP-1 and DP-2. Participation in the pilot requires either an AMI meter or an existing Interval Data Recorder ("IDR") meter at the customer location. The meter records energy usage every 30 minutes, which enables the Company to offer pricing that varies based on the time of day. In addition, the pricing varies based on the season, the classification for the day, and the customer's demand. Therefore, the AMI or IDR meter coupled with the dynamic pricing schedules allows customers to manage their energy costs based on the time of day. Additional information regarding the Pilot is available at http://www.dom.com/smartprice.

Status:

The Dynamic Pricing Pilot program was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011. On July 31, 2015, the Company filed a Motion to Extend the Pilot, which was approved December 18, 2015. The Pilot is scheduled to end on July 31, 2017. The Company launched this Pilot program on July 1, 2011. As of December 2015, there were 569 customers taking service under the residential DP-R tariff; 61 customers taking service under the commercial DP-1 tariff; and 76 customers taking service under the commercial DP-2 tariff.

Electric Vehicle ("EV") Pilot

State: Virginia

Target Class: Residential

Pilot Type: Peak-Shaving

Pilot Duration: Enrollment began October 3, 2011

Enrollment was scheduled to conclude December 1, 2015, but is allowed on an interim basis while the Company's Motion to Extend is considered.

The Pilot is scheduled to conclude November 30, 2016.

Description:
On January 31, 2011, the Company filed an application with the SCC (Case No. PUE-2011-00014) proposing a pilot program to offer experimental and voluntary EV rate options to encourage residential customers who purchase or lease EVs to charge them during off-peak periods. The Pilot program provides two rate options. One rate option, a "Whole House" rate, allows customers to apply the time-of-use rate to their entire service, including their premises and vehicle. The other rate option, an "EV Only" rate, allows customers to remain on the existing residential rate for their premises and subscribe to the time-of-use rate only for their vehicle. The program is open to up to 1,500 residential customers, with up to 750 in each of the two experimental rates. Additional information regarding the Company's EV Pilot Program is available in the Company's application, in the SCC's Order Granting Approval, and at https://www.dom.com/electricvehicle.

Status:
The SCC approved the Pilot in July 2011. The Company began enrollment on October 3, 2011, enrollment was scheduled to conclude on December 1, 2015. On October 30, 2015, the Company filed a petition to extend enrollment through September 1, 2016 and extend the Pilot through November 30, 2018. An order is pending, but the SCC allowed enrollment to continue on an interim basis until a final order is issued. As of December 2015, 367 customers were enrolled on the whole-house EV rate while 119 customers were enrolled on the EV-only rate.

AMI Upgrades

State: Virginia

Target Class: All Classes

Type: Energy Efficiency

Duration: Ongoing

Description:
The Company continues to upgrade meters to Advanced Metering Infrastructure, also referred to as smart meters.

Status:
As of December 2015, the Company has installed over 360,000 smart meters in areas throughout Virginia. The AMI meter upgrades are part of an on-going project that will help the Company further evaluate the effectiveness of AMI meters in achieving voltage conservation, voltage stability,

remotely turning off and on electric service, power outage, restoration detection and reporting, remote daily meter readings and offering dynamic rates.

3.2.4 CURRENT CONSUMER EDUCATION PROGRAMS

The Company's consumer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption. The Company's website has a section dedicated to energy conservation. This section contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Through consumer education, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina. Examples of how the Company increases customer awareness include:

Customer Connection Newsletter

State: Virginia and North Carolina

The Customer Connection newsletter contains news on topics such as DSM programs, how to save money or manage electric bills, helping the environment, service issues, and safety recommendations, in addition to many other relevant subjects. Articles from the most recent Virginia Customer Connection Newsletter are located on the Company's website at: https://www.dom.com/residential/dominion-virginia-power/news/customer-newsletters. Articles from the most recent North Carolina Customer Connection Newsletter are located on the Company's website at: https://www.dom.com/residential/dominion-north-carolina-power/news/customer-newsletters.

Twitter® and Facebook

State: Virginia and North Carolina

The Company uses the social media channels of Twitter® and Facebook to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers. The Twitter® account is available online at: www.twitter.com/DomVAPower. The Facebook account is available online at: http://www.facebook.com/dominionvirginiapower.

"Every Day"

State: Virginia

The Company advertises the "Every Day" campaign, which is a series of commercial and print ads that address various energy issues. These advertisements, along with the Company's other advertisements, are available at: https://www.dom.com/corporate/news/advertisements.

News Releases

State: Virginia and North Carolina

The Company prepares news releases and reports on the latest developments regarding its DSM initiatives and provides updates on Company offerings and recommendations for saving energy as new information becomes available. Current and archived news releases can be viewed at: https://www.dom.com/corporate/news/news-releases.

Online Energy Calculators

State: Virginia and North Carolina

Home and business energy calculators are provided on the Company's website to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: https://www.dom.com/residential/dominion-virginia-power/ways-to-save/energy-saving-calculators.

Community Outreach - Trade Shows, Exhibits and Speaking Engagements

State: Virginia and North Carolina

The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation program information to both internal and external audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's DSM programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses. Additionally, Company representatives positively impact the communities served through presentations to elementary, middle, and high school students about programs, using energy wisely and environmental stewardship.

The Company also provides helpful materials for students to share with their families. For example, Project Plant It! is an innovative community program available to elementary school students in Virginia, North Carolina, Connecticut, Maryland, Pennsylvania, and New York that teaches students about the importance of trees and how to protect the environment. This program includes interactive classroom lessons and provides students with tree seedlings to plant at home or at school. The Company offers Project Plant It! free of charge throughout the Company's service territory and has distributed 306,327 seedlings through the program since 2007.

DSM Program Communications

The Company uses numerous methods to make customers aware of its DSM programs. These methods include direct mail, communications through contractor networks, e-mail, radio ads, social media, and outreach events.

3.2.5 APPROVED DSM PROGRAMS

In North Carolina, in Docket No. E-22, SUB 523, the Company filed for NCUC approval of the Residential Income and Age Qualifying Home Improvement Program. This is the same program that was approved in Virginia in Case No. PUE-2014-00071. On October 6, 2015, the NCUC approved the new program, which has been available to qualifying North Carolina customers since January 2016.

Appendix 3M provides program descriptions for the currently-approved DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and plans to achieve each program's penetration goals. Appendices 3N, 3O, 3P and 3Q provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved program.

For the Air Conditioner Cycling and Distributed Generation Programs, each has utilization parameters such as number of implementation calls per season or year, advanced notice required to implement the load reduction, hours per initiation, and total hours of use per season or year. The rate structures of the programs essentially pay for the use parameters and are considered fixed costs, which do not affect individual program implementation calls. As such, the Company targets full utilization of the programs to the extent that there are opportunities to reduce demand during peak load situations or during periods when activation would otherwise be cost-effective and not unduly burdensome to participating customers.

While the Company targets full utilization of the Air Conditioner Cycling Program, it is important to consider the participating customers' comfort and overall satisfaction with the program as well. The Company recognizes the value of the Air Conditioner Cycling Program and continues to monitor customer retention with respect to program activation.

Over the past few years, the Company has refined its approach to activation of the programs. Experience indicates that it is important to use a combination of factors to determine when a program should be activated. These factors include load forecasts, activation costs, system conditions, and PJM Locational Marginal Pricing ("LMP") of energy. By including consideration of LMPs in the decision-making process relative to program activation costs, the cost of fuel is implicitly accounted for but is not treated as the sole determinant for dispatching a program.

The Company assumes there is a relationship between the number of hours the program is dispatched and the number of hours needed to reduce load during critical peak periods. It is assumed that there is a relationship between the incentive amount and the number of control hours called. As the number of control hours increases, the incentive amount would also have to increase in order to maintain the same amount of customers, potentially rendering the program not cost-effective. The Company continues to make every effort to balance the need to achieve peak load reduction against program cost and customer experience.

3.2.6 PROPOSED DSM PROGRAMS

The Commonwealth of Virginia has an energy reduction target for 2022 of reducing the consumption of electric energy by retail customers by an amount equal to 10% of the amount of electric energy consumed by retail customers in 2006, as applied to the Company's 2006 jurisdictional retail sales. The Company has expressed its commitment to helping Virginia reach this goal. Related to and consistent with the goal, DSM Programs are an important part of the Company's portfolio available to meet customers' growing need for electricity along with supply-side resources.

On August 28, 2015, as part of Case No. PUE-2015-00089, the Company filed in Virginia for SCC approval of two new DSM Programs ("Phase V DSM Programs"). The two proposed Programs are the i) Residential Programmable Thermostat Program and ii) Small Business Improvement Program. Both Programs are classified as energy efficiency programs, as that classification is defined under Va. Code § 56-576. In addition, the Company is requesting the extension of the Phase I Residential Air Conditioner Cycling Program. On April 19, 2016, the Commission issued its Final Order approving the Small Business Improvement Program and the Air Conditioner Cycling Program, subject to certain conditions, and denying the Residential Programmable Thermostat Program.

Appendix 3R provides program descriptions for the proposed DSM programs. Appendices 3S, 3T, 3U and 3V provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each of the Virginia Proposed Programs.

3.2.7 EVALUATION, MEASUREMENT & VERIFICATION

The Company has implemented EM&V plans to quantify the level of energy and demand savings for approved DSM programs in Virginia and North Carolina. As required by the SCC and NCUC, the Company provides annual EM&V reports that include: i) the actual EM&V data; ii) the cumulative results for each DSM program in comparison to forecasted annual projections; and iii) any recommendations or observations following the analysis of the EM&V data. These annual reports are filed on April 1 with the SCC and NCUC and will provide information through the prior calendar year. DNV GL (formerly DNV KEMA Energy & Sustainability), a third-party vendor, continues to be responsible for developing, executing, and reporting the EM&V results for the Company's currently-approved DSM programs.

3.3 TRANSMISSION RESOURCES

3.3.1 EXISTING TRANSMISSION RESOURCES

The Company has over 6,500 miles of transmission lines in Virginia, North Carolina and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

3.3.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

North Carolina Plan Addendum 2 contains the list of Company's existing transmission and distribution lines listed in pages 422, 423, 424, 425, 426 and 427, respectively, of the Company's most recently filed Federal Energy Regulatory Commission ("FERC") Form 1.

3.3.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

The Company currently does not have any transmission interconnection projects under construction (Appendix 3W). A list of the Company's transmission lines and associated facilities that are under construction may be found in Appendix 3X.

CHAPTER 4 – PLANNING ASSUMPTIONS

4.1 PLANNING ASSUMPTIONS INTRODUCTION

In this 2016 Plan, the Company relies upon a number of assumptions including requirements from PJM. This Chapter discusses these assumptions and requirements related to capacity needs, reserve requirements, renewable energy requirements, commodity price assumptions, and transmission assumptions. The Company updates its IRP assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1.1 CLEAN POWER PLAN ASSUMPTIONS

The primary assumption that the Company used for the CPP-Compliant Alternative Plans described in Chapter 6 is that the CPP final rule goes into effect as promulgated. The CPP-Compliant Alternative Plans were designed in a manner so that Virginia could achieve CPP compliance independently with little or no reliance on other states or the market to achieve such compliance. This independent method, or "island" approach, included minimal purchases of energy and capacity, and no purchases of ERCs or CO_2 allowances. Although the Company expects markets for CPP ERCs and CO_2 allowances to evolve, the Company maintains this approach is prudent for modeling purposes at this time in light of the uncertainty surrounding future markets for ERCs and CO_2 allowances that as of today do not exist. Also, the CPP-Compliant Alternative Plans assume that the run-time of the Company's Mt. Storm Power Station, located in West Virginia, is limited to a 40% capacity factor. This assumption is based on the Company's view that West Virginia: (i) will elect a Mass-Based CPP compliance program; and (ii) will allocate allowances to affected units in West Virginia using the methodology based on a unit's pro-rata share of the average 2010 – 2012 statewide generation as proposed in the model trading rule. This allocation method would provide Mt. Storm a quantity of emission allowances representative of about a 40% operational annual capacity factor.

Even though the Company modeled the system as an island, the Company favors CPP programs that encourage trading of ERCs and/or CO_2 allowances. Trading provides a clear market price signal which is the most efficient means of emission mitigation. Also, trading offers flexibility in the event of years with unit outages or non-normal weather. As the evolution of the CPP trading markets materialize once the EPA model trading rules are finalized and SIPs are developed, the Company will incorporate ERC and CO_2 allowance trading into its analysis.

Since the state of Virginia has not selected a compliance option nor have some of the CPP details been finalized, the Company assumed that it would be allocated 70% of the total allowances under the state Mass-Based Cap compliance options. This is based on the Company's average share of the statewide total CO_2 emissions in the 2012 baseline year. Allowance set-asides were not incorporated in the Mass-Based Plans because of uncertainty in whether or how they would be established and distributed. However, if set-asides are part of the Mass-Based State Plan, the Company believes it will earn approximately 70% of the set-aside allowances, which means the Company will continue to receive overall 70% of all Virginia allowances, to the extent allowances are distributed directly to affected generating units.

As shown in Chapter 6, a key resource contributing towards CPP-compliance that is utilized by the Company in this 2016 Plan is solar photovoltaic ("PV"). As discussed in Chapter 5, current solar PV technology produces intermittent energy that is non-dispatchable and subject to sudden changes in generation output along with voltage inconsistencies. Therefore, integrating large volumes of solar PV resources into the Company's grid presents service reliability challenges that the Company continues to examine and study (a complete discussion of the status of this study is included in Chapter 5). Overcoming these challenges will most likely add additional cost that at this time remains undetermined by the Company. As such, for every kW of solar PV added to any of the CPP-Complaint Alternative Plans described in Chapter 6, a $390.43/kW charge was added to the cost of solar PV to function as a proxy for grid integration cost. This proxy charge is based on the cost of one set of two CT units for every 1,000 MW of solar PV nameplate capacity. It should also be noted that this assumption was only used to approximate solar PV integration costs. In other words, no actual CTs were added to any of the CPP-Compliant Alternative Plans identified in Chapter 6 as a solar back-up.

4.2 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

The Company participates in the PJM capacity planning processes for short- and long-term capacity planning. A brief discussion of these processes and the Company's participation in them is provided in the following subsections.

4.2.1 SHORT-TERM CAPACITY PLANNING PROCESS – RPM

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines. PJM then conducts a capacity auction through its Short-Term Capacity Planning Process (i.e., the RPM auction) for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the delivery year that is three years in the future (e.g., 2016 auction procured capacity for the delivery year 2019/2020).

The Company, as a generation provider, bids its capacity resources, including owned and contracted generation and DSM programs, into this auction. As an LSE, the Company is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the RPM auction, or through any bilateral trades. Figure 4.2.2.1 provides the Company's estimated 2017 to 2019 capacity positions and associated reserve margins based on PJM's January 2016 Load Forecast and RPM auctions that have already been conducted.

4.2.2 LONG-TERM CAPACITY PLANNING PROCESS – RESERVE REQUIREMENTS

The Company uses PJM's reserve margin guidelines in conjunction with its own load forecast discussed in Chapter 2 to determine its long-term capacity requirement. PJM conducts an annual Reserve Requirement Study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a Loss of Load Expectation ("LOLE") equivalent to one day of outage in 10 years. PJM's 2015 Reserve Requirement Study[7] for delivery year 2019/2020,

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7 PJM's current and historical reserve margins are available at: http://www.pjm.com/~/media/committees-groups/committees/mc/20141120/20141120-item-02c-2014-reserve-requirement-study.ashx.

recommends using an installed reserve margin ("IRM") of 16.5% to satisfy the NERC/Reliability First Corporation ("RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation.

PJM develops reserve margin estimates for planning years (referred to as "delivery years" for RPM) rather than calendar years. Specifically, PJM's planning year occurs from June 1st of one year to May 31st of the following year. Since the Company and PJM are both historically summer peaking entities, and since the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time period. For example, the Company uses PJM's 2018/2019 delivery year assumptions for the 2018 calendar year in this 2016 Plan because both represent the expected peak load during the summer of 2018.

Two assumptions were made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, since PJM uses a shorter planning period than the Company, the Company used the most recent PJM Reserve Requirements Study and assumed the reserve margin value for delivery year 2019 and beyond would continue throughout the Study Period.

The second assumption pertains to the coincident factor between the DOM Zone coincidental and non-coincidental peak load. The Company is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load. Since the Company's peak load (non-coincidental) has not historically occurred during the same hour as PJM's peak load (coincidental), a smaller reserve margin is needed to meet reliability targets and is based on a coincidence factor. To determine the coincidence factor used in this 2016 Plan, the Company used a four-year (2016 - 2019) average of the coincidence factor between the DOM Zone coincidental and non-coincidental peak load. The coincidence factor for the Company's load is approximately 96.53% as calculated using PJM's January 2016 Load Forecast. In 2019, applying the PJM IRM requirement of 16.5% with the Company's coincidence factor of 96.53% resulted in an effective reserve margin of 12.46%, as shown in Figure 4.2.2.1. This effective reserve margin was then used for each year for the remainder of the Planning Period.

As a member of PJM, the Company participates in the annual RPM capacity markets. PJM's RPM construct has historically resulted in a clearing reserve margin in excess of the planned reserve margin requirement. The average PJM RPM clearing reserve margin is 19.58% over the past five years.[8] Using the same analysis approach described above, this equates to an approximate 15.43% effective reserve requirement. With the RPM clearing capacity in excess of its target level, the Company has purchased reserves in excess of the 12.46% planning reserve margin, as reflected in Figure 4.2.2.1. Given this history, the figures in Appendix 1A display a second capacity requirement target is also shown, that includes an additional 5% reserve requirement target (17.46% reserve margin) that is commensurate with the upper bound where the RPM market has historically cleared; however, the Company's planning reserve margin minimum target remains at the 12.46% average

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8 See http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx.

clearing level. The upper bound reserve margin reflects the reserve margin that the Company may be required to meet in the future.

Figure 4.2.2.1 - Peak Load Forecast & Reserve Requirements

Year	PJM Installed Reserve Margin Requirements[1]	DVP Effective Reserve Margin Requirements	Total System Summer Peak	Adjusted System Summer Peak[3]	Reserve Requirement	Total Resource Requirement[2]
	%	%	MW		MW	MW
2017	-	23.04%	17,262	17,207	3,964	21,171
2018	-	21.46%	17,633	17,578	3,773	21,351
2019	-	17.93%	17,890	17,835	3,197	21,032
2020	16.50%	12.46%	19,125	18,891	2,354	21,245
2021	16.50%	12.46%	19,490	19,257	2,399	21,657
2022	16.50%	12.46%	19,738	19,509	2,431	21,940
2023	16.50%	12.46%	19,952	19,724	2,457	22,181
2024	16.50%	12.46%	20,362	20,132	2,508	22,640
2025	16.50%	12.46%	20,630	20,399	2,542	22,941
2026	16.50%	12.46%	20,828	20,597	2,566	23,163
2027	16.50%	12.46%	21,024	20,792	2,590	23,382
2028	16.50%	12.46%	21,186	20,953	2,611	23,563
2029	16.50%	12.46%	21,432	21,197	2,641	23,838
2030	16.50%	12.46%	21,814	21,579	2,689	24,267
2031	16.50%	12.46%	22,103	21,866	2,724	24,591

Notes: 1) 2017 – 2019 values reflect the Company's position following RPM base residual auctions that have cleared.
2) Includes wholesale obligations.
3) Includes energy efficiency.

In Figure 4.2.2.1, the total resource requirement column provides the total amount of peak capacity including the reserve margin used in this 2016 Plan. This represents the Company's total resource need that must be met through existing resources, construction of new resources, DSM programs, and market capacity purchases. Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annually updated load and reserve requirements. Appendix 2I provides a summary of summer and winter peak load and energy forecast, while Appendix 2J provides a summary of projected PJM reserve margins for summer peak demand.

Finally, the industry's compliance with effective and anticipated EPA regulations concerning air, water, and solid waste constituents influenced the retirement decision of numerous coal plants, which either have already retired or are scheduled to retire over the next several years. The EPA's CPP will apply additional operational limits on fossil fuel-fired generation, particularly coal units, which may lead to the retirement of additional fossil fuel-fired generation. Considering the large number of generation units retirements that have to-date occurred and the potential for additional plant retirements along with the long-lead times required to develop replacement generation, a period of uncertainty as to the availability of power from outside the service territory may develop over the next several years. Therefore, the Company maintains that it is prudent to plan for a higher capacity reserve margin and not expose its customers to an overreliance on market purchases during this uncertain period of time beginning now and extending beyond the 2022 time period.

4.3 RENEWABLE ENERGY

4.3.1 VIRGINIA RPS

On May 18, 2010, the SCC issued its Final Order granting the Company's July 28, 2009 application to participate in Virginia's voluntary Renewable Energy Portfolio Standards ("RPS") program finding that "the Company has demonstrated that it has a reasonable expectation of achieving 12 percent of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15 percent of its base year electric energy sales from renewable energy sources during calendar year 2025" (Case No. PUE-2009-00082, May 18, 2010 Final Order at 7). The RPS guidelines state that a certain percent of the Company's energy is to be obtained from renewable resources. The Company can meet Virginia's RPS program guidelines through the generation of renewable energy, purchase of renewable energy, purchase of RECs, or a combination of the three options. The Company achieved its 2014 Virginia RPS Goal. Figure 4.3.1.1 displays Virginia's RPS goals.

Figure 4.3.1.1 - Virginia RPS Goals

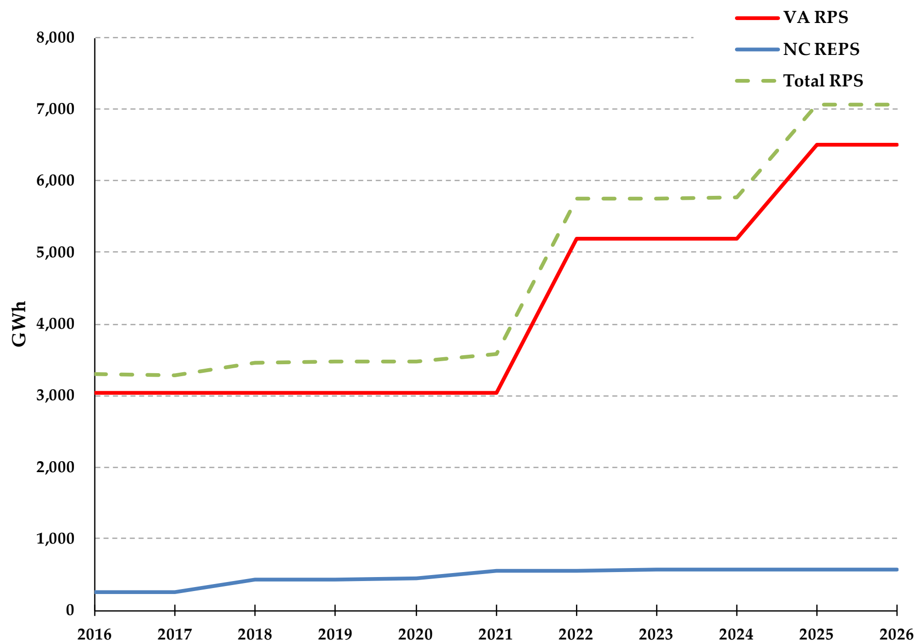
Year	Percent of RPS	Annual GWh[1]
2015	Average of 4% of Base Year Sales	1,732
2016	7% of Base Year Sales	3,032
2017-2021	Average of 7% of Base Year Sales	3,032
2022	12% of Base Year Sales	5,198
2023-2024	Average of 12% of Base Year Sales	5,198
2025	15% of Base Year Sales	6,497

Note: 1) Base year sales are equal to 2007 Virginia jurisdictional retail sales, minus 2004 to 2006 average nuclear generation. Actual goals are based on MWh.

The Company has included renewable resources as an option in Strategist, taking into consideration the economics and RPS requirements. If there are adequate supplies of waste wood available at the time, VCHEC is expected to provide up to 61 MW of renewable generation by 2021. The Studied Plans include 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020, and 12 MW of offshore wind (VOWTAP) capacity as early as 2018. The Company reiterates its intent to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner by: i) applying renewable energy from existing generating facilities including NUGs; ii) purchasing cost-effective RECs (including optimizing RECs produced by Company-owned generation when these higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS goals); and iii) constructing new renewable resources when and where feasible.

The renewable energy requirements for Virginia and North Carolina and their totals are shown in Figure 4.3.1.2.

Figure 4.3.1.2 - Renewable Energy Requirements



4.3.2 NORTH CAROLINA REPS

NCGS § 62-133.8 requires the Company to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") requirements. The REPS requirements can be met by generating renewable energy, energy efficiency measures (capped at 25% of the REPS requirements through 2020 and up to 40% thereafter), purchasing renewable energy, purchasing RECs, or a combination of options as permitted by NCGS § 62-133.8 (b) (2). The Company plans to meet a portion of the general REPS requirements using the approved energy efficiency programs discussed in Chapters 3 and 6 of this Plan. The Company achieved compliance with its 2014 North Carolina REPS general obligation by using approved North Carolina energy efficiency savings, banked RECs and purchasing additional qualified RECs during 2014. In addition, the Company purchased sufficient RECs to comply with the solar and poultry waste set-aside requirements. However, on December 1, 2015, in response to the Joint Motion to Modify and Delay, the NCUC delayed the Company's 2015 swine waste set-aside requirement one year and delayed the poultry waste set-aside requirement increase for one year. More information regarding the Company's REPS compliance planning is available in its North Carolina REPS Compliance Plan filed in North Carolina with this 2016 Plan as North Carolina Plan Addendum 1. Figure 4.3.2.1 displays North Carolina's overall REPS requirements.

Figure 4.3.2.1 - North Carolina Total REPS Requirements

Year	Percent of REPS	Annual GWh[1]
2016	6% of 2015 DNCP Retail Sales	260
2017	6% of 2016 DNCP Retail Sales	257
2018	10% of 2017 DNCP Retail Sales	431
2019	10% of 2018 DNCP Retail Sales	435
2020	10% of 2019 DNCP Retail Sales	438
2021	12.5% of 2020 DNCP Retail Sales	552
2022	12.5% of 2021 DNCP Retail Sales	557
2023	12.5% of 2022 DNCP Retail Sales	561
2024	12.5% of 2023 DNCP Retail Sales	566
2025	12.5% of 2024 DNCP Retail Sales	570
2026	12.5% of 2025 DNCP Retail Sales	575

Note: 1) Annual GWh is an estimate only based on the latest forecast sales. The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry waste, and swine waste through the purchase of RECs and/or purchased energy, as applicable. These set-aside requirements represent approximately 0.03% of system load by 2024 and will not materially alter this integrated resource plan.

As part of the total REPS requirements, North Carolina requires certain renewable set-aside provisions for solar energy, swine waste, and poultry waste resources, as shown in Figure 4.3.2.2, Figure 4.3.2.3, and Figure 4.3.2.4.

Figure 4.3.2.2 - North Carolina Solar Requirement

Year	Requirement Target (%)	Annual GWh[1]
2016	0.14% of 2015 DNCP Retail Sales	6.06
2017	0.14% of 2016 DNCP Retail Sales	5.99
2018	0.14% of 2017 DNCP Retail Sales	8.63
2019	0.20% of 2018 DNCP Retail Sales	8.63
2020	0.20% of 2019 DNCP Retail Sales	8.70
2021	0.20% of 2020 DNCP Retail Sales	8.77
2022	0.20% of 2021 DNCP Retail Sales	8.84
2023	0.20% of 2022 DNCP Retail Sales	8.91
2024	0.20% of 2023 DNCP Retail Sales	8.98
2025	0.20% of 2024 DNCP Retail Sales	9.05
2026	0.20% of 2025 DNCP Retail Sales	9.12

Notes: 1) Annual GWh is an estimate based on latest forecast sales.

Figure 4.3.2.3 - North Carolina Swine Waste Requirement

Year	Target	Dominion Market Share (Est.)	Annual GWh[1]
2016	0.07% of 2015 NC Retail Sales	2.96%	3.03
2017	0.07% of 2016 NC Retail Sales	2.96%	3.00
2018	0.14% of 2017 NC Retail Sales	3.00%	6.04
2019	0.14% of 2018 NC Retail Sales	2.99%	6.14
2020	0.14% of 2019 NC Retail Sales	2.99%	6.19
2021	0.20% of 2020 NC Retail Sales	2.97%	8.91
2022	0.20% of 2021 NC Retail Sales	2.97%	8.98
2023	0.20% of 2022 NC Retail Sales	2.90%	9.05
2024	0.20% of 2023 NC Retail Sales	2.88%	9.12
2025	0.20% of 2024 NC Retail Sales	2.86%	9.20
2026	0.20% of 2025 NC Retail Sales	2.85%	9.32

Note: 1) Annual GWh is an estimate based on the latest forecast sales.

Figure 4.3.2.4 - North Carolina Poultry Waste Requirement

Year	Target[1] (GWh)	Dominion Market Share (Est.)	Annual GWh[1]
2016	700	2.96%	20.72
2017	900	2.96%	26.64
2018	900	3.00%	26.55
2019	900	2.99%	26.34
2020	900	2.99%	26.21
2021	900	2.97%	26.08
2022	900	2.97%	25.95
2023	900	2.90%	25.82
2024	900	2.88%	25.70
2025	900	2.86%	25.57
2026	900	2.85%	25.44

Note: 1) For purposes of this filing, the Poultry Waste Resource requirement is calculated as an aggregate target for NC electric suppliers distributed based on market share.

4.4 COMMODITY PRICE ASSUMPTIONS

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis in this 2016 Plan using energy and commodity price forecasts provided by ICF International, Inc. ("ICF"), a global energy consulting firm, in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal and power prices rely on forward market prices as of November 30, 2016, for the first 18 months and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity prices, NO_x and SO_2 allowance prices are provided by ICF for all years forecasted by this year's integrated resource plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM Base Residual Auction through the 2018/2019 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2019/2020 delivery year.

Consistent with the 2015 Plan, the Company utilizes the No CO_2 Cost forecast to evaluate the Plan A: No CO_2 Limit and the CPP commodity forecast to evaluate the CPP-Compliant Alternative Plans as listed in Figure 6.6.1. The primary reason for utilizing this method is to allow the Company to evaluate the CPP-Compliant Alternative Plans using a commodity price forecast that reflects the CPP. Plan A: No CO_2 Limit assumes no new CO_2 laws or regulations whatsoever; therefore, it was evaluated using a commodity price forecast without the influence of CO_2 prices. The ICF Reference Case scenario was developed utilizing a similar methodology, with updated assumptions, as used to develop the basecase commodity price forecast in integrated resource plans developed by the Company in years prior to the CPP. The ICF Reference Case models CO_2 using a probability weighted methodology. The primary difference between the CPP commodity forecast and the ICF Reference Case is that the CPP commodity forecast reflects CO_2 regulations consistent with the CPP, while the ICF Reference Case considers the possibility of delays in implementation, potential modification of CO_2 regulations, and/or longer-term CO_2 regulation that may be more or less stringent than the CPP. The High and Low Fuel Cost scenarios are based on the same CO_2 regulation assumptions as the CPP commodity forecast. In summary, the primary commodity price forecast used to analyze the CPP-Compliant Alternative Plans is the CPP commodity forecast while the No CO_2 commodity price forecast was used to evaluate Plan A: No CO_2 Limit. Scenarios were evaluated on each of the Studied Plans using the ICF Reference Case, High Fuel Cost and the Low Fuel Cost commodity forecast.

4.4.1 CPP COMMODITY FORECAST

The CPP commodity forecast is utilized as the primary planning curve for evaluation in this 2016 Plan. The forecast was developed for the Company to specifically address the EPA's CPP, which intends to control CO_2 emissions from existing fossil-fired generators with an interim target for 2022-2029 and final targets in 2030. The key assumptions on market structure and the use of an integrated, internally-consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecast. With consideration to the inherent uncertainty as to the final outcome of the legal challenges, trading rules, and state specific compliance plans developed for CPP, the modeling methods utilized state designations of Intensity-Based and Mass-Based developed by ICF. Given that very few states have indicated what approach they will take, ICF is not projecting these designations as the paths states would take, but is assessing uncertainties with the understanding that it is unlikely that all states will choose the same or similar paths forward. The designations were based on a combination of factors including: whether the state is a party to the CPP lawsuit, is a participant in an existing Mass-Based CO_2 program, or engages in renewable development and nuclear development. The states projected to settle on a Mass-Based program for existing units are assumed to participate in a nationwide trading program for CO_2 allowances. States projected to settle on an Intensity-Based program are generally large creators of ERCs. A list of the projected programs for each state is provided in Appendix 4A (page A-95). The modeling results in the price forecasts for two CO_2 related commodities, a carbon allowance measured in $/ton and an ERC measured in $/MWh. States projected to pursue a Mass-Based program on existing units will be buyers or sellers of CO_2 allowances, and those states that pursue an Intensity-Based program will be buyers and sellers of ERCs. The CPP commodity price forecast used in the IRP process assumed that Virginia adopts an Intensity-Based program, as the state specific compliance plan.

The Company also requested ICF provide a commodity price forecast that assumed Virginia adopts a Mass-Based compliance plan. Comparison of the commodity prices between the two programs reveals very little difference in fuel, power, renewable energy credits and ERC/CO_2 allowance prices based on Virginia adopting an Intensity-Based or Mass-Based program. Given the similarities between the forecast, the Company elected to use the commodity prices associated with Virginia adopting an Intensity-Based program as the primary planning curve used in the IRP process. For the evaluation of an Intensity-Based CPP program in Virginia, the cost of carbon is represented by an ERC; for the evaluation of a Mass-Based CPP program, the carbon cost is represented by a CO_2 allowance price. The primary difference between commodity prices in adoption of an Intensity- versus a Mass-Based program in Virginia then is whether the forecasted price of CO_2 allowances (Mass-Based program), is greater than the forecasted price of ERCs (Intensity-Based program). The future price of ERCs versus CO_2 allowances is an important factor that states should consider when assessing an Intensity-Based program versus a Mass-Based program. This is because the expected prices of those instruments provide insight into the cost of compliance should EGUs have to purchase ERCs or CO_2 allowances from the marketplace. If an EGU was forced to purchase ERCs or CO_2 allowances from the market, then under the CPP compliance price forecast an Intensity-Based program is lower cost than a Mass-Based program.

The forecast of ERC prices indicates a zero value, as it is anticipated the market will be oversupplied with ERCs. The value of ERCs is ultimately contingent on (1) the type of compliance plan adopted by states that elect to pursue an Intensity-Based approach to CPP compliance, (2) the notion that all ERCs generated will be offered to the market, (3) the probability that there will be no changes to ERC eligibility, and (4) the continued development of the types of generators that produce ERCs. Given the uncertainty inherent to a program that is determined by the actions of others, the Company continues to pursue plans that will be CPP-compliant without consistent reliance on market purchases of ERCs. In other words, ERCs will only be relied upon to fill temporary shortfalls in compliance levels. The Company believes this is the most prudent methodology to compliance as it provides CPP-Compliant Alternative Plans that comply with CPP requirements regardless of actions of other market participants.

A summary of the CPP commodity forecasts for the 2016 Plan and the CPP forecast used in the 2015 Plan are provided below. As discussed earlier in this section, the CPP commodity forecast is the primary planning curve for evaluating the CPP-Compliant Alternative Plans (Figure 6.6.1), and the ICF Reference Case is used as a scenario for all of the Studied Plans. The primary reason for this is to allow the Company to evaluate the CPP-Compliant Alternative Plans using a commodity price forecast that reflects the current status of the CPP regulation. Appendix 4B provides delivered fuel prices and primary fuel expense from the Strategist model output using the CPP commodity forecast. Figures 4.4.1.1 - 5 display the fuel price forecasts, while Figures 4.4.1.6 displays the forecasted price for SO_2 and NO_x on a dollar per ton basis. Figure 4.4.1.7 displays CO_2 emissions allowances ($/ton) and ERC Prices ($/MWh). Figures 4.4.1.8 - 9 present the forecasted market clearing peak power prices for the PJM DOM Zone. The PJM RTO capacity price forecast is presented in Figure 4.4.1.10.

Figure 4.4.1.1 - Fuel Price Forecasts - Natural Gas Henry Hub

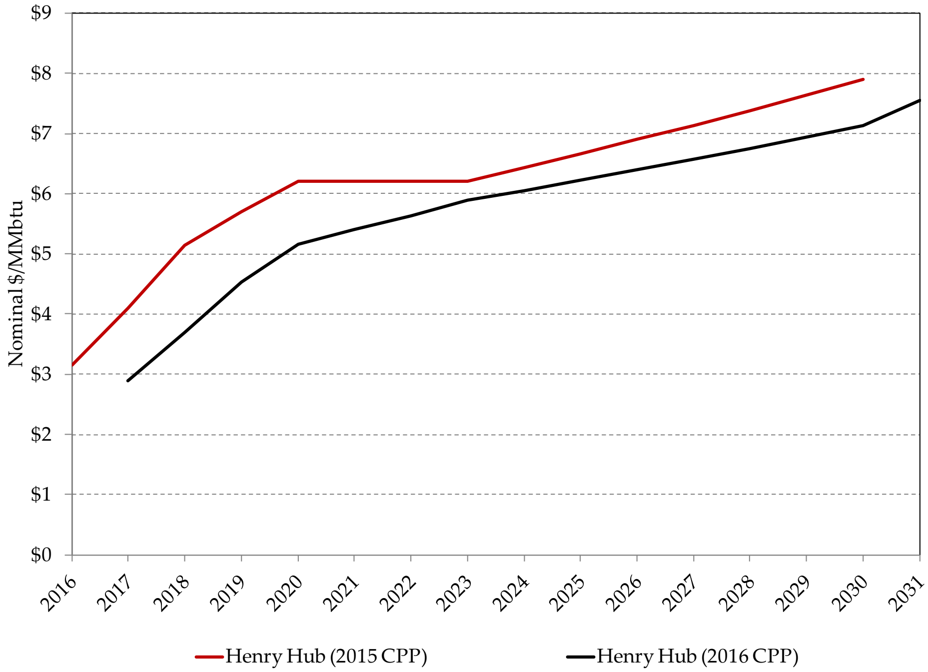


Figure 4.4.1.2 - Fuel Price Forecasts - Natural Gas DOM Zone

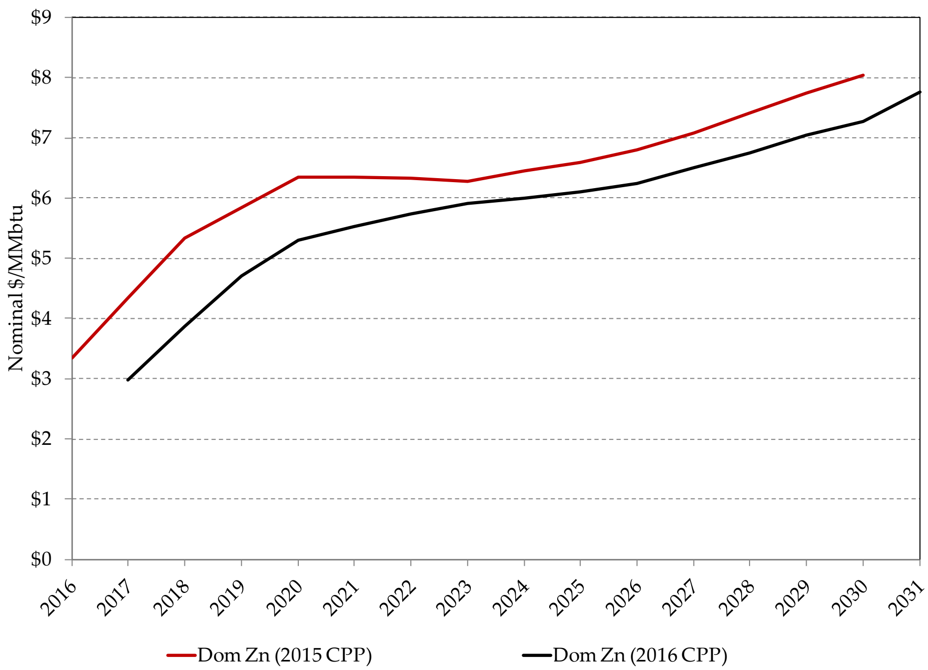


Figure 4.4.1.3 - Fuel Price Forecasts - Coal

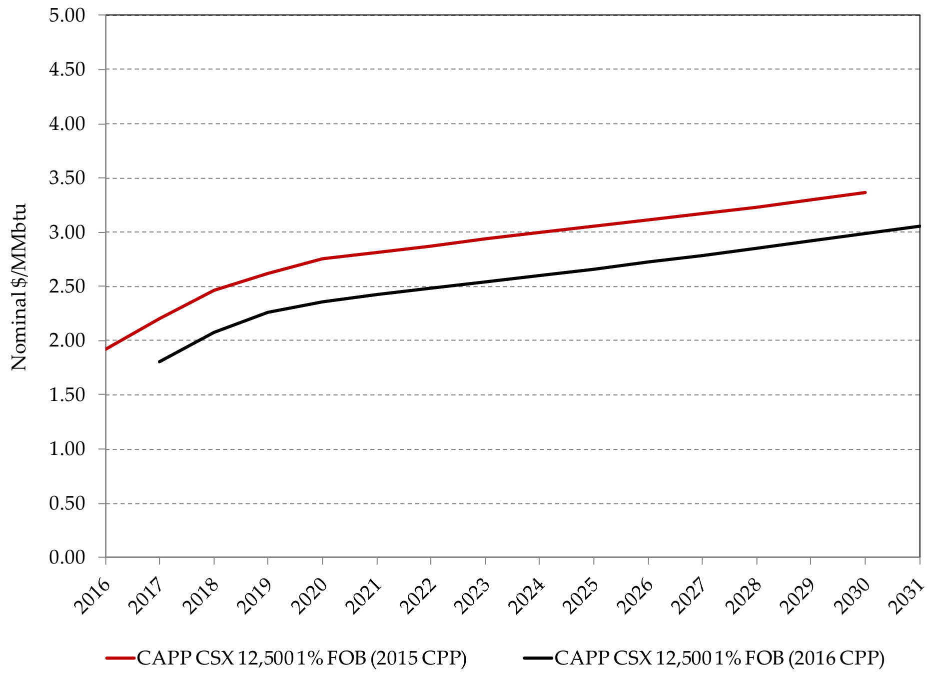


Figure 4.4.1.4 - Fuel Price Forecasts - #2 Oil

Figure 4.4.1.5 - Price Forecasts – #6 Oil

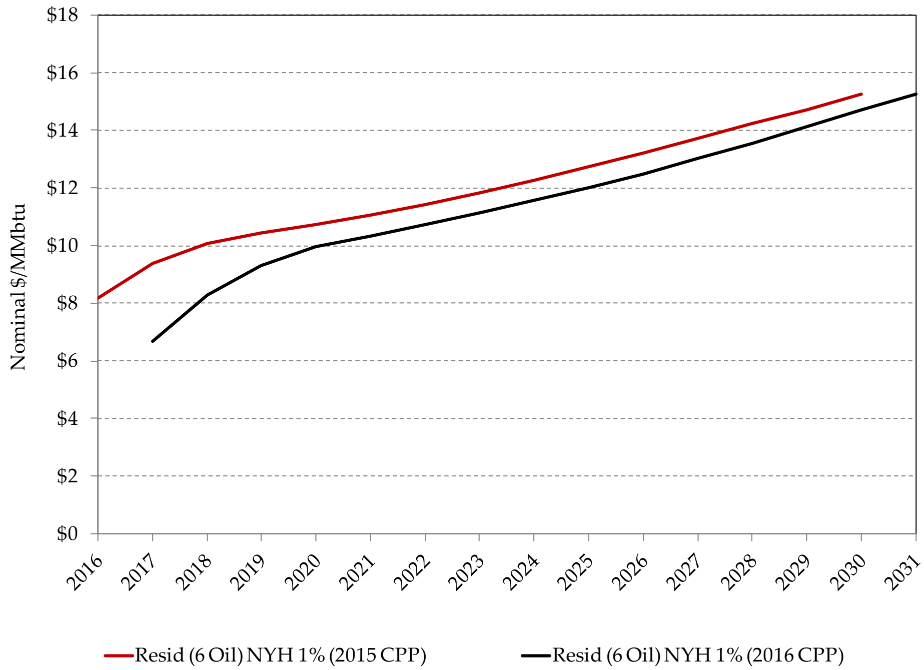


Figure 4.4.1.6 - Price Forecasts – SO2 & NOx

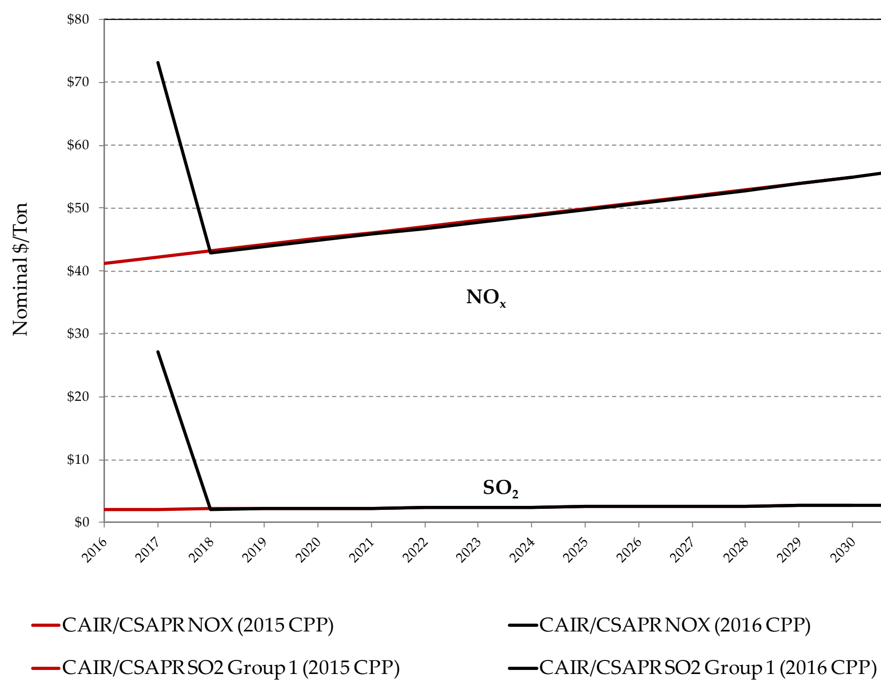
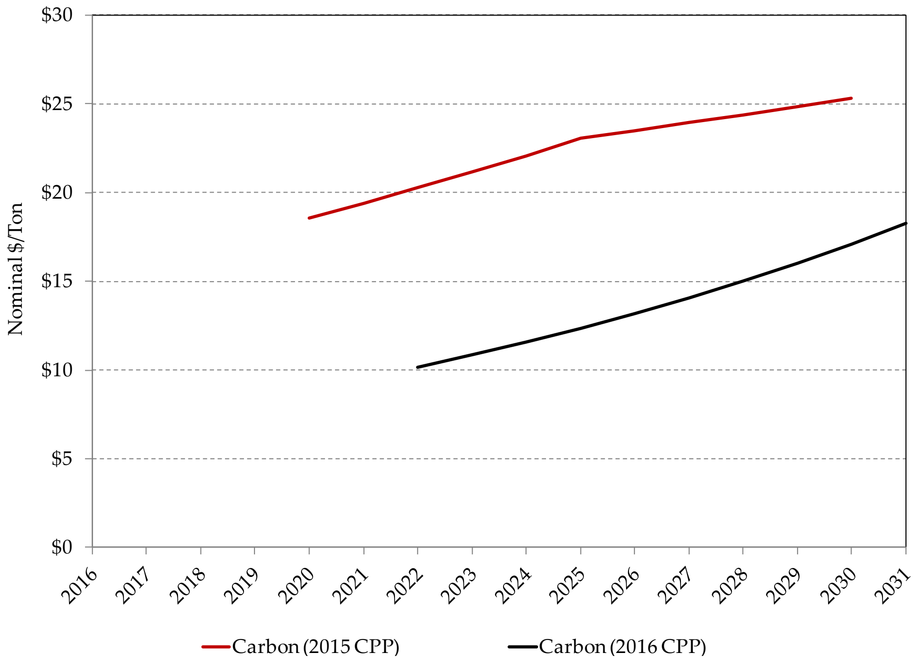


Figure 4.4.1.7 - Price Forecasts - CO_2



Note: The CPP commodity forecast used in the 2016 Plan includes both an ERC and CO_2 allowance price. The ERC forecast is in $/MWh and applies to states adopting an Intensity-Based compliance program. ERCs are forecast at $0/MWh as those states projected to adopt an Intensity-Based compliance program are projected to generate an abundance of ERCs. The CO_2 allowance price forecast is in $/ton and applies to states adopting a Mass-Based compliance program. The CPP commodity forecast in the 2015 Plan utilized a shadow price for CO_2. The shadow price was reflective of the marginal cost of complying with the emissions cap specified in the CPP as proposed at that time. The shadow price was specific to Virginia and did not reflect a national or regional trading program.

Figure 4.4.1.8 - Power Price Forecasts – On Peak

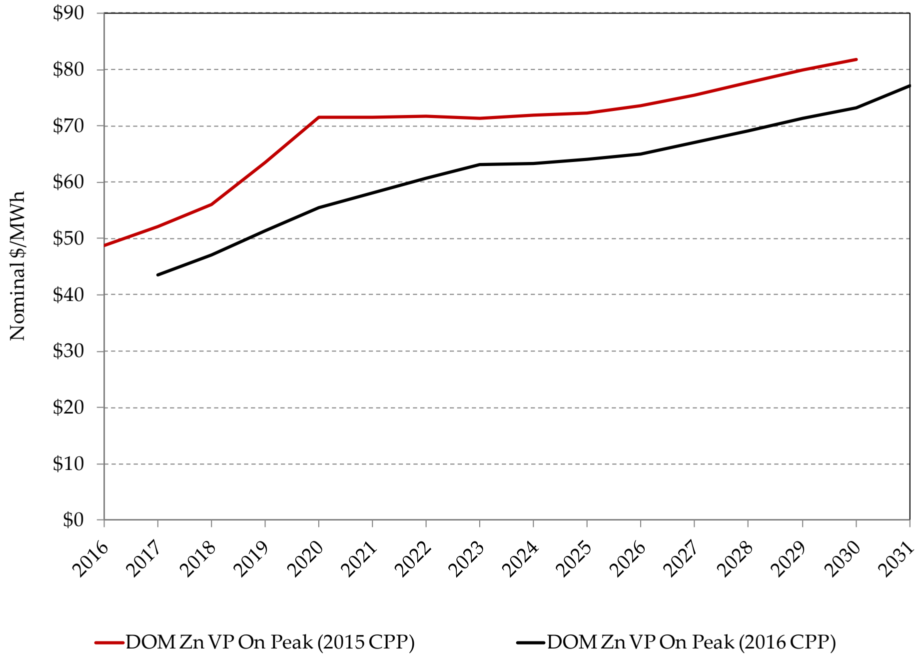


Figure 4.4.1.9 - Power Price Forecasts – Off Peak

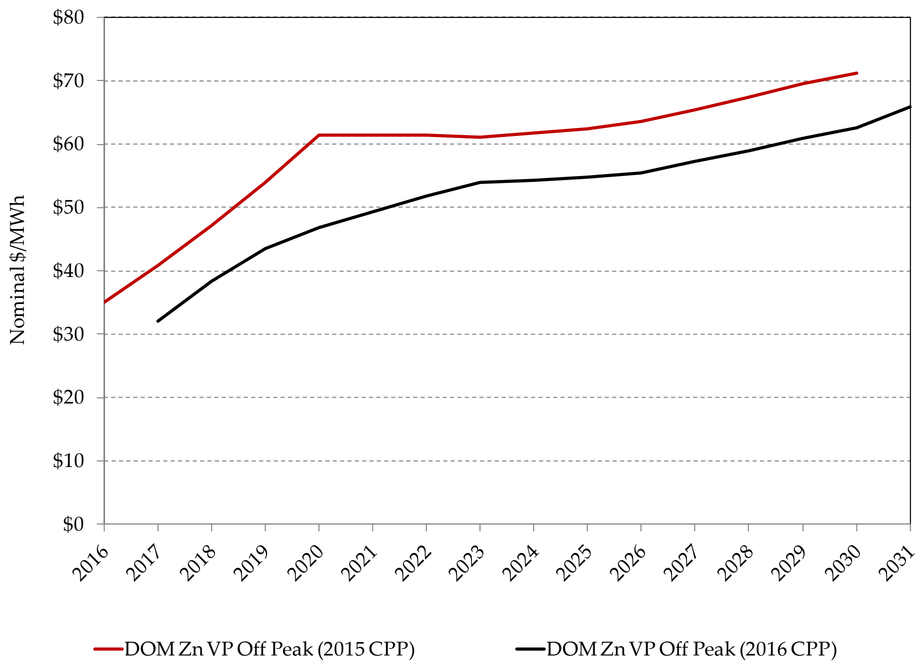
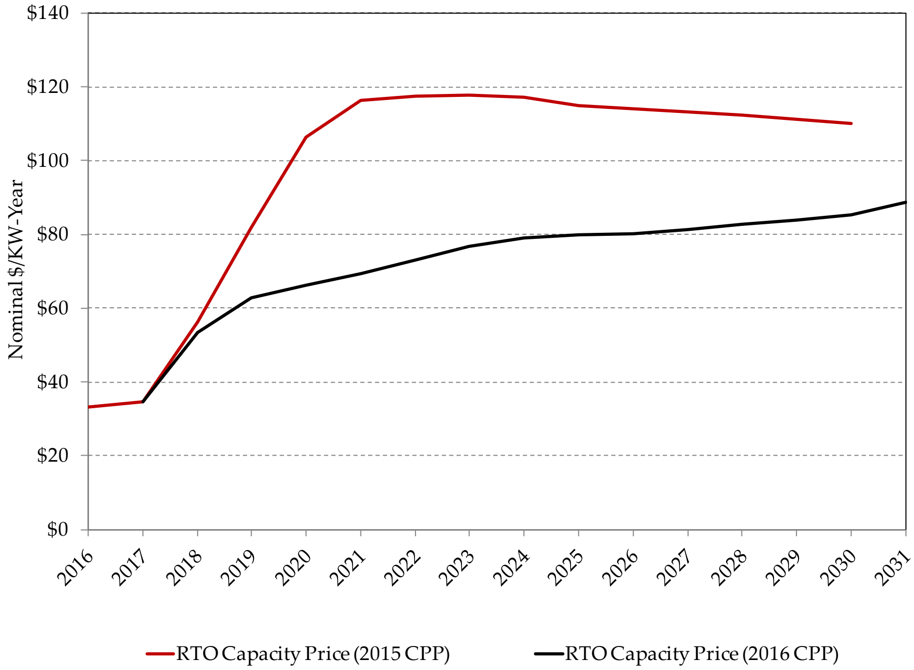


Figure 4.4.1.10 - PJM RTO Capacity Price Forecasts



As seen in the above figures, the forecast of power and gas prices are lower this year than forecast in the 2015 Plan, primarily due to the continued decrease in cost and increase in volume of the shale gas resources. The most significant decline in power prices occurs in 2020 and 2021, due to the delay in the start of CPP. Prices for Central Appalachian coal are lower, reflecting current market conditions including lower power prices, which are marginalizing existing coal generation and regulations discouraging the development of new coal generation. Capacity prices are lower, reflecting removal of the costs associated with including firm transportation for natural gas to meet the PJM Capacity Performance Product requirements in the RPM capacity auction. Figure 4.4.1.11 presents a comparison of average fuel, electric, and REC prices used in the 2015 Plan relative to those used in this 2016 Plan.

Figure 4.4.1.11 - 2015 to 2016 Plan Fuel & Power Price Comparison

	Planning Period Comparison Average Value (Nominal $)	
Fuel Price	2015 Plan CPP Commodity Forecast [3]	2016 Plan CPP Commodity Forecast [3]
Henry Hub Natural Gas[1] ($/MMbtu)	6.20	5.79
DOM Zone Delivered Natural Gas[1] ($/MMbtu)	6.28	5.85
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.85	2.57
No. 2 Oil ($/MMbtu)	17.62	17.12
1% No. 6 Oil ($/MMbtu)	11.95	11.55
Electric and REC Prices		
PJM-DOM On-Peak ($/MWh)	69.26	61.96
PJM-DOM Off-Peak ($/MWh)	58.89	52.40
PJM Tier 1 REC Prices ($/MWh)	17.17	22.10
RTO Capacity Prices[2] ($/KW-yr)	97.12	73.17

Note: 1) DOM Zone natural gas price used in plan analysis. Henry Hub prices are shown to provide market reference.
2) Capacity price represents actual clearing price from PJM Reliability Pricing Model. Base Residual Auction results through power year 2017/2018 for the 2015 Plan and 2018/2019 for the 2016 Plan.
3) 2015 Planning Period 2016 – 2030, 2016 Planning Period 2017 – 2031.

4.4.2 ALTERNATIVE SCENARIO COMMODITY PRICES

The alternative commodity price forecast scenarios represent reasonable outcomes for future commodity prices based on alternate views of key fundamental drivers of commodity prices. However, as with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity price scenarios developed for this year's integrated resource plan. History has shown that unforeseen events can result in significant change in market fundamentals. These events were not contemplated five or 10 years before such an occurrence. Several recent examples include the shale gas revolution that transformed the pricing structure of natural gas. Another recent example is the scheduled retirement of numerous generation units, fueled primarily by coal, in response to low gas prices, an aging coal fleet, and environmental compliance cost.

The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecast scenarios analyzed in this 2016 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but not all possible outcomes. In this 2016 Plan, the Company has included a comprehensive risk analysis that provides a more robust assessment of possible price forecast outcomes. A description of this analysis is included in Chapter 6. The Company preserves its supply-side development options, including renewable and nuclear, as a necessary tool in a prudent long-term planning process in part because of unforeseen events. The comprehensive risk analysis included in Section 6.8.1 further reinforces this premise.

The Company performed analysis using three alternative pricing scenarios. The methodology of using scenarios in the IRP process is further explained in Section 6.6. The scenarios used in the analysis include (1) ICF Reference Case, (2) High Fuel Cost and (3) Low Fuel Cost. The High Fuel Cost and Low Fuel Cost scenarios were developed using CO_2 regulatory assumptions consistent with the CPP commodity forecast (Virginia Intensity-Based CPP program) discussed in Section 4.4.1. The scenarios are intended to represent a reasonably likely range of prices, not the absolute boundaries of higher or lower prices.

The ICF Reference Case forecasts current market conditions and ICF's independent internal views of key market drivers. Key drivers include market structure and policy elements that shape allowance, fuel and power markets, ranging from expected capacity and pollution control installations, environmental regulations, and fuel supply-side issues. The ICF Reference Case provides a forecast of prices for fuel, energy, capacity, emission allowances and RECs. The methodology used to develop the forecast relies on an integrated, internally-consistent, fundamentals-based analysis. The development process assesses the impact of environmental regulations on the power and fuel markets and incorporates ICF's latest views on the outcome of new regulatory initiatives.

In the ICF Reference Case, CO_2 regulation assumptions represent a probability weighted outcome of legislative and regulatory initiatives, including the possibility of no regulatory program addressing CO_2 emissions. A charge on CO_2 emissions from the power sector is assumed to begin in 2022 reflecting the timing for regulation of existing unit NSPS for the CPP.

The ICF Reference Case CO_2 price forecast considers three potential outcomes. The first possible outcome considers a $0/ton CO_2 price; the second possible outcome considers a tradable mass based program (limit on tonnage of CO_2 emissions) on existing and new sources based on the requirements of the CPP; and a third possible outcome considers a more stringent CPP post-2030. The $0/ton price can be thought of as either no-program (due to successful legal challenges to CPP or otherwise), a "behind-the-fence" requirement without a market-based CO_2 price, or a program that relies on complementary measures, such as tax credits for non-emitting generation sources, in place of a CO_2 program. The second possible outcome is based on the requirements of the final CPP assuming that states adopt Mass-Based standards within a regional trading structure and address leakage by including new sources under the cap (adjusted with the new source complements from the final rule). The third case assumes a national mass cap based on an extension of the CPP Best System of Emission Reduction ("BSER") calculation targeting 50% renewable generation by 2050. This case could also reflect a legislative approach to CO_2 control similar to what was proposed under the Waxman-Markey legislation. The ICF Reference Case assumed a 50% probability for the $0/ton outcome and a 50% probability for the mass cap based program beginning in 2022. By 2040, the probability of a CO_2 price by means of the mass cap based program or a more stringent CPP type program increases to 90%. The resulting CO_2 price forecast rises from a little over $5.70/ton in 2022 to a little over $36/ton, (nominal $) in 2035 in the ICF Reference Case.

Prices of natural gas and power are lower over the long term in the CPP commodity forecast than in the ICF Reference Case. The CO_2 emission target levels in the CPP commodity forecast remain static at the 2030 level and CPP regulations modeled emissions are not applied to new units (emissions limited by rate established for new generation sources). In the ICF Reference Case, emission requirements are applied to all fossil units and become more stringent with time, using a nationwide CO_2 price that continues to increase providing a direct price signal to the power markets.

As discussed earlier in this section, the CPP commodity forecast is the primary planning curve for evaluating the CPP-Compliant Alternative Plans (Figure 6.6.1) and the ICF Reference Case is used as a scenario for all of the Studied Plans.

The High Fuel Cost scenario represents possible future market conditions where key market drivers create upward pressure on commodity and energy prices during the Planning Period. This scenario reflects a correlated increase in commodity prices which, when compared to the CPP commodity forecast, provides an average increase of approximately 12% for natural gas, 8% for coal, and 9% for the PJM DOM Zone peak energy prices during the Planning Period. The drivers behind higher natural gas prices could include lower incremental production growth from shale gas reservoirs, higher costs to locate and produce natural gas, and increased demand. Higher prices for coal could result from increasing production costs due to increased safety requirements, more difficult geology, and higher stripping ratios. The High Fuel Cost scenario is based on the same CO_2 regulation assumptions as the CPP commodity forecast (Virginia Intensity-Based CPP program). Analysis of Intensity-Based and Mass-Based scenarios in the Strategist model utilized the same commodity price forecast with the exception that in an Intensity-Based scenario, the cost of carbon is represented by an ERC, and in a Mass-Based scenario, the cost of carbon is represented by the CO_2 allowance price.

The Low Fuel Cost scenario represents possible future market conditions where key market drivers create downward pressure on commodity and energy prices during the Planning Period. This scenario reflects a correlated price decrease in natural gas that averages approximately 11%, coal price drops by approximately 15%, and PJM DOM Zone peak energy prices are lower by approximately 8% across the Planning Period when compared to the CPP commodity forecast. The drivers behind lower natural gas prices could include higher incremental production growth from shale gas reservoirs, lower costs to locate and produce natural gas, and lower demand. Lower coal prices could result from improved mining productivity due to new technology and improved management practices, and cost reductions associated with mining materials, supplies, and equipment. The Low Fuel Cost scenario is based on the same CO_2 regulation assumptions as the CPP commodity forecast (Virginia Intensity-Based CPP program). Consistent with the High Fuel Cost scenario, analysis of Intensity-Based and Mass-Based CPP scenarios in the Strategist model utilized the same commodity price forecast with the exception of that in an Intensity-Based scenario the ERC prices are used as a carbon cost and in a Mass-Based scenario the CO_2 allowance price is used as a carbon cost.

The Company utilizes the No CO_2 Cost forecast to evaluate Plan A: No CO_2 Limit. In this forecast, the cost associated with carbon emissions projected to commence in 2022 is removed from the forecast. The cost of CO_2 being removed has an effect of reducing natural gas prices by 6% from the CPP commodity forecast across the Planning Period due to reduced natural gas generation in the absence of a federal CO_2 program. DOM Zone peak energy prices are on average 7% lower than the CPP commodity forecast across the Planning Period due to lower natural gas prices and no CO_2 cost to pass through to power prices.

Appendix 4A provides the annual prices (nominal $) for each commodity price alternative scenario. Figure 4.4.2.1 provides a comparison of the CPP case, the No CO_2 Cost Case and the three alternative scenarios.

Figure 4.4.2.1 - 2016 Plan Fuel & Power Price Comparison

	2017 - 2031 Average Value (Nominal $)				
Fuel Price	CPP Commodity Forecast	ICF Reference Case	High Fuel Cost	Low Fuel Cost	No CO_2 Cost
Henry Hub Natural Gas ($/MMbtu)	5.79	5.98	6.48	5.17	5.42
DOM Zone Delivered Natural Gas ($/MMbtu)	5.85	6.04	6.54	5.23	5.48
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.57	2.56	2.78	2.18	2.59
No. 2 Oil ($/MMbtu)	17.12	17.12	19.91	15.48	17.12
1% No. 6 Oil ($/MMbtu)	11.55	11.55	13.54	10.37	11.55
Electric and REC Prices					
PJM-DOM On-Peak ($/MWh)	61.96	65.44	67.37	57.10	57.34
PJM-DOM Off-Peak ($/MWh)	52.40	55.62	57.32	47.85	47.83
PJM Tier 1 REC Prices ($/MWh)	22.10	17.73	18.60	25.00	25.76
RTO Capacity Prices ($/KW-yr)	73.17	80.82	69.49	77.42	86.82

4.5 DEVELOPMENT OF DSM PROGRAM ASSUMPTIONS

The Company develops assumptions for new DSM programs by engaging vendors through a competitive bid process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. The Company generally prefers, to the extent practical, that the program design vendor is ultimately the same vendor that implements the program in order to maintain as much continuity as possible from design to implementation. This approach is not possible for every program, but is preferred when circumstances allow.

The DSM program design process includes evaluating programs as either a single measure, like the Residential Heat Pump Tune-Up Program, or multi-measure, like the Non-Residential Energy Audit Program. For all measures in a program, the design vendor develops a baseline for a standard customer end-use technology. The baseline establishes the current energy usage for a particular appliance or customer end-use. Next, assumptions for a more efficient replacement measure or end-use are developed. The difference between the more efficient energy end-use and the standard end-use provides the incremental benefit that the Company and customer will achieve if the more efficient energy end-use is implemented.

The program design vendor's development of assumptions for a DSM program include determining cost estimates for the incremental customer investment in the more efficient technology, the incentive that the Company should pay the customer to encourage investment in the DSM measure, and the program cost the Company will likely incur to administer the program. In addition to the cost assumptions for the program, the program design vendor develops incremental demand and energy reductions associated with the program. This data is represented in the form of a load shape for energy efficiency programs which identifies the energy reductions by hour for each hour of the year (8,760 hour load shape).

The Company then uses the program assumptions developed by the program design vendor to perform cost/benefit tests for the programs. The cost/benefit tests assist in determining which programs are cost-effective to potentially include in the Company's DSM portfolio. Programs that pass the Company's evaluation process are included in the Company's DSM portfolio, subject to appropriate regulatory approvals.

4.6 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this 2016 Plan, electric transmission facilities at the Company can be generally defined as those operating at 69 kV and above that provide for the interchange of power within and outside of the Company's system.

4.6.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

The Company's transmission system is designed and operated to ensure adequate and reliable service to its customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC standards.

The Company participates in numerous regional, interregional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM, an RTO responsible for the movement of wholesale electricity. PJM is registered with NERC as the Company's Planning Coordinator and Transmission Planner. Accordingly, the Company participates in the PJM Regional Transmission Expansion Plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a five-year and a 15-year outlook.

The Company evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation will indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate and, if the need is confirmed, then the Company seeks approval from the appropriate regulatory body. Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. It is essential to maintain an adequate level of transfer capability between neighboring utilities to facilitate economic and emergency power flows, and the Company coordinates with other utilities to maintain adequate levels of transfer capability.

4.6.2 STATION SECURITY

As part of the Company's overall strategy to improve its transmission system resiliency and security, the Company is installing additional physical security measures at substations and switching stations in Virginia and North Carolina. The Company announced these plans publicly following the widely-reported April 2013 Metcalfe Substation incident in California.

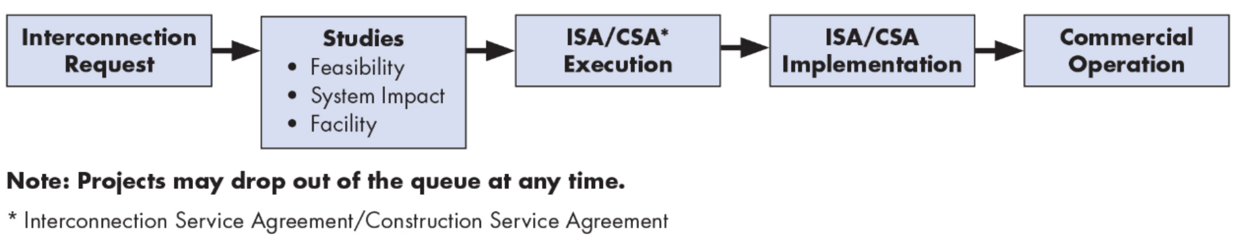
As one of the region's largest electricity suppliers, the Company proposed to spend up to $500 million by 2022 to increase the security for its transmission substations and other critical infrastructure against man-made physical threats and natural disasters, as well as stockpile crucial equipment for major damage recovery. These new security facilities will be installed in accordance with recently approved NERC mandatory compliance standards. In addition, the Company is moving forward with constructing a new System Operations Center to be commissioned by 2017.

4.6.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts Feasibility Studies, System Impact Studies, and Facilities Studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.6.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of the PJM manual 14A[9] and the Company's Facility Connection Requirements.[10]

The results of these studies provide the requesting interconnection customer with an assessment of the feasibility and costs (both interconnection facilities and network upgrades) to interconnect the proposed facilities to the PJM system, which includes the Company's transmission system.

Figure 4.6.3.1 - PJM Interconnection Request Process



Source: PJM

The Company's planning objectives include analyzing planning options for transmission, as part of the IRP process, and providing results that become inputs to the PJM planning processes. In order to accomplish this goal, the Company must comply and coordinate with a variety of regulatory groups that address reliability, grid expansion, and costs which fall under the authority of NERC, PJM, FERC, the SCC, and the NCUC. In evaluating and developing this process, balance among regulations, reliability, and costs are critical to providing service to the Company's customers in all aspects, which includes generation and transmission services.

The Company also evaluates and analyzes transmission options for siting potential generation resources to offer flexibility and additional grid benefits. The Company conducts power flow studies and financial analysis to determine interconnection requirements for new supply-side resources.

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[9] The PJM manual 14A is posted at http://www.pjm.com/~/media/documents/manuals/m14a.ashx.

[10] The Company's Facility Connection Requirements are posted at https://www.dom.com/library/domcom/pdfs/electric-transmission/facility-connection-requirements.pdf.

The Company uses Promod IV®, which performs security constrained unit commitment and dispatch, to consider the proposed and planned supply-side resources and transmission facilities. Promod IV®, incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations, and is the industry-leading fundamental electric market simulation software.

The Promod IV® model enables the Company to integrate the transmission and generation system planning to: i) analyze the zonal and nodal level LMP impact of new resources and transmission facilities, ii) calculate the value of new facilities due to the alleviation of system constraints, and iii) perform transmission congestion analysis. The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities, while providing reliable service to all customers. The Promod IV® model evaluates the impact of resources under development that are selected by the Strategist model. Specifically, this Promod IV® LMP analysis was conducted for the Brunswick County Power Station, as well as the Greensville County Power Station. In addition, the Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid.

4.7 GAS SUPPLY, ADEQUACY AND RELIABILITY

In maintaining its diverse generating portfolio, the Company manages a balanced mix of fuels that includes fossil, nuclear and renewable resources. Specifically, the Company's fleet includes units powered by natural gas, coal, petroleum, uranium, biomass (waste wood), water, and solar. This balanced and diversified fuel management approach supports the Company's efforts in meeting its customers' growing demand by responsibly and cost-effectively managing risk. By avoiding overreliance on any single fuel source, the Company protects its customers from rate volatility and other harms associated with shifting regulatory requirements, commodity price volatility and reliability concerns.

Electric Power and Natural Gas Interdependency

It is projected that nearly 49% of capacity additions occurring over the next 10 years will be gas-fired, and by 2025, natural gas will make up 43% of the projected on-peak resource mix. [11] With a production shift from conventional to an expanded array of unconventional gas sources (such as shale) and relatively low commodity price forecasts, gas-fired generation is the first choice for new capacity, overtaking and replacing coal-fired capacity.

However, the electric grid's exposure to interruptions in natural gas fuel supply and delivery has increased with the generating capacity's growing dependence on a single fuel. Natural gas is largely delivered on a just-in-time basis, and vulnerabilities in gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies – such as storage, firm fuel contracts, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and overall fuel diversity all help to alleviate this risk.

[11] NERC 2015 Long-Term Reliability Assessment; December, 2015; Pg. 12

There are two types of pipeline delivery service contracts – firm and interruptible service. Natural gas provided under a firm service contract is available to the customer at all times during the contract term and is not subject to a prior claim from another customer. For a firm service contract, the customer typically pays a facilities charge representing the customer's share of the capacity construction cost and a fixed monthly capacity reservation charge. Interruptible service contracts provide the customer with natural gas subject to the contractual rights of firm customers. The Company currently uses a combination of both firm and interruptible service to fuel its gas-fired generation fleet. As the percentage of natural gas use increases in terms of both energy and capacity, the Company intends to increase its use of firm transport capacity to help ensure reliability and price stability.

Pipeline deliverability can impact electrical system reliability. A physical disruption to a pipeline or compressor station can interrupt or reduce the flow pressure of gas supply to multiple electric generating units at once. Electrical systems also have the ability to adversely impact pipeline reliability. The sudden loss of a large efficient generator can cause numerous smaller gas-fired CTs to be started in a short period of time. This sudden change in demand may cause drops in pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric gas compressor stations, which can disrupt the fuel supply to electric generators.

As a result, the Company routinely assesses the gas-electric reliability of its system. The results of these assessments show that current interruptions on any single pipeline are manageable, but as the Company and the electric industry shift to a heavier reliance on natural gas, additional actions are needed to ensure future reliability and rate stability. Additionally, equipping future CCs and CTs with dual-fuel capability may be needed to further enhance the reliability of the electric system.

System Planning

In general, electric transmission service providers maintain, plan, design, and construct systems that meet federally-mandated NERC Reliability Standards and other requirements, and that are capable of serving forecasted customer demands and load growth. A well-designed electrical grid, with numerous points of interconnection and facilities designed to respond to contingency conditions, results in a flexible, robust electrical delivery system.

In contrast, pipelines generally are constructed to meet new load growth. FERC does not authorize new pipeline capacity unless customers have already committed to it via firm delivery contracts, and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, in order for a pipeline to add or expand facilities, existing or new customers must request additional firm service. The resulting new pipeline capacity closely matches the requirements of the new firm capacity request. If the firm customers accept all of the gas under their respective contracts, little or no excess pipeline capacity will be available for interruptible customers. This is a major difference between pipeline infrastructure construction and electric transmission system planning because the electric system is expanded to address current or projected system conditions and the costs are typically socialized across customers.

Actions
The Company is aware of the risks associated with natural gas deliverability and has been proactive in mitigating these risks. For example, the Company continues to secure firm natural gas pipeline transportation service for all new CC facilities, including Bear Garden, Warren County, Brunswick County, and the Greensville County Power Station, that is under development. Additionally, the Company maintains a portfolio of firm gas transportation to serve a portion of its remaining gas generation fleet.

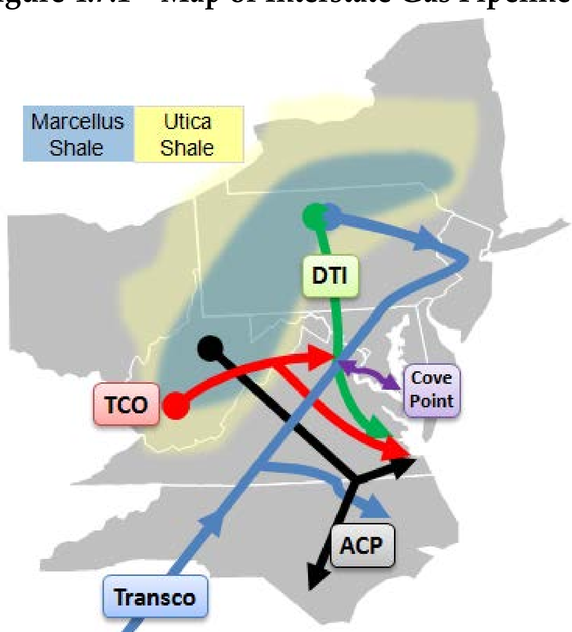
Atlantic Coast Pipeline
In August 2014, the Company executed a precedent agreement to secure firm transportation services on the ACP. This incremental capacity will support a portion of the natural gas needs for the existing power generation with enhanced fueling flexibility and reliability.

Currently, natural gas is primarily transported into the Company's service territory via four interstate pipelines:

- Transco – Transcontinental Gas Pipe Line;
- TCO – Columbia Gas Transmission;
- DTI – Dominion Transmission Inc.; and
- Cove Point Pipeline – Dominion Transmission Inc.

The ACP is a greenfield interstate pipeline that will provide access to competitively-priced, domestic natural gas supply for utility and industrial customers in Virginia and North Carolina and deliver those supplies to strategic points in the Company's service territory as early as November 2018. As seen in Figure 4.7.1, this geographically-diverse pipeline would also allow for future, lower-cost pipeline capacity expansions with limited environmental impact.

Figure 4.7.1 – Map of Interstate Gas Pipelines



CHAPTER 5 – FUTURE RESOURCES

5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor viable commercial- and utility-scale emerging generation technologies and to gather information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including, but not limited to, planning, financial analysis, construction, operations, and business development. The dispatchable and non-dispatchable resources examined in this 2016 Plan are defined and discussed in the following subsections.

5.1.1 DISPATCHABLE RESOURCES

Aero-derivative Combustion Turbine

The Company is examining aero-derivative turbines (< 100 MW) for possible consideration in future IRPs. These turbines possess quick start capabilities, vary their output quickly (ramp up and ramp down), and have proven to be reliable under multiple start-up/shut-down cycles. The flexibility offered by these types of machines may be useful in compensating for sudden generation changes that are characteristic of intermittent generation resources like solar PV. These resources have the ability to react quickly from varying intermittent resources to support bulk electric grid stability. At the time of this 2016 Plan, the Company is still assessing these types of machines. Therefore, aero-derivative turbines were not considered in the Company's busbar analysis.

Biomass

Biomass generation facilities rely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel primarily used is waste wood, which is carbon neutral. Greenfield biomass was considered for further analysis in the Company's busbar curve analysis; however, it was found to be uneconomic. Generally, biomass generation facilities are geographically limited by access to a fuel source.

Circulating Fluidized Bed ("CFB")

CFB combustion technology is a clean coal technology that has been operational for the past few decades and can consume a wide array of coal types and qualities, including low Btu waste coal and wood products. The technology uses jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants, such as NO_x and SO_2. The preferred location for this technology is within the vicinity of large quantities of waste coal fields. The Company will continue to track this technology and its associated economics based on the site and fuel resource availability. With strict standards on emissions from the electric generating unit GHG NSPS rule, this resource was not considered for further analysis in the Company's busbar curve analysis, as these regulations effectively prevent permitting new coal units.

Coal with Carbon Capture and Sequestration ("CCS") [12]

Coal generating technology is very mature with hundreds of plants in operation across the United States and others under various stages of development. CCS is a new and developing technology designed to collect and trap CO_2 underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal-burning facilities. The targets for new electric generating units, as currently proposed under the CPP NSPS 111(b), would require all new fossil fuel-fired electric generation resources to meet a strict limit for CO_2 emissions. To meet these standards, CCS technology is assumed to be required on all new coal, including supercritical pulverized coal ("SCPC") and integrated-gasification combined-cycle ("IGCC") technologies. Coal generation with CCS technology, however, is still under development and not commercially available. The Company will continue to track this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve analysis.

IGCC with CCS[13]

IGCC plants use a gasification system to produce synthetic natural gas from coal in order to fuel a CC. The gasification process produces a pressurized stream of CO_2 before combustion, which, research suggests, provides some advantages in preparing the CO_2 for CCS systems. IGCC systems remove a greater proportion of other air effluents in comparison to traditional coal units. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve analysis.

Energy Storage

There are several different types of energy storage technologies. Energy storage technologies include, but are not limited to, pumped storage hydroelectric power, superconducting magnetic energy storage, capacitors, compressed air energy storage, flywheels, and batteries. Cost considerations have restricted widespread deployment of most of these technologies, with the exception of pumped hydroelectric power and batteries.

The Company is the operator and a 60% owner in the Bath County Pumped Storage Station, which is one of the world's largest pumped storage generation stations, with a net generating capacity of 3,003 MW. Due to their size, pumped storage facilities are best suited for centralized utility-scale applications.

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for power station, blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Recently, batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology approximates dispatchability for these variable energy resources. The primary challenge facing

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[12] The Company currently assumes that the captured carbon cannot be sold.

[13] The Company currently assumes that the captured carbon cannot be sold.

battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems.

The Company is actively engaged in the evaluation of the potential for energy storage technologies to provide ancillary services, to improve overall grid efficiency, and to enhance distribution system reliability. Due to the location limitations associated with pumped storage facilities, these resources were not considered for further analysis in the Company's busbar curve analysis. Batteries coupled with solar PV, however, were included in the busbar curve analysis. The curve attempts to show the cost of increasing the reliability and dispatchability of solar PV.

Fuel Cell

Fuel cells are electrochemical cells that convert chemical energy from fuel into electricity and heat. They are similar to batteries in their operation, but where batteries store energy in the components (a closed system), fuel cells consume their reactants. Although fuel cells are considered an alternative energy technology, they would only qualify as renewable in Virginia or North Carolina if powered by a renewable energy resource as defined by the respective state's statutes. This resource was considered for further analysis in the Company's busbar curve analysis.

Gas-Fired Combined-Cycle

A natural gas-fired CC plant combines a CT and a steam turbine plant into a single, highly-efficient power plant. The Company considered CC generators, with heat recovery steam generators and supplemental firing capability, based on commercially-available advanced technology. The CC resources were considered for further analysis in the Company's busbar curve analysis.

Gas-Fired Combustion Turbine

Natural gas-fired CT technology has the lowest capital requirements ($/kW) of any resource considered; however, it has relatively high variable costs because of its low efficiency. This is a proven technology with cost information readily available. This resource was considered for further analysis in the Company's busbar curve analysis.

Geothermal

Geothermal technology uses the heat from the earth to create steam that is subsequently run through a steam turbine. The National Renewable Energy Laboratory ("NREL") has indicated that currently there are not any viable sites for geothermal technology identified in the eastern portion of the United States.[14] The Company does not view this resource as a feasible option in its service territory at this time. This resource was not considered for further analysis in the Company's busbar curve analysis.

Hydro

Facilities powered by falling water have been operating for over a century. Construction of large-scale hydroelectric dams is currently unlikely due to environmental restrictions in the Company's

[14] Retrieved from: http://www.nrel.gov/geothermal/.

service territory; however, smaller-scale plants, or run-of-river facilities, are feasible. Due to the site-specific nature of these plants, the Company does not believe it is appropriate to further investigate this type of plant until a viable site is available. This resource was not considered for further analysis in the Company's busbar curve analysis.

Nuclear

With a need for clean, non-carbon emitting baseload power, and nuclear power's proven record of low operating costs, around the clock availability, and zero emissions, many electric utilities continue to examine new nuclear power units. The process for constructing a new nuclear unit remains time-consuming with various permits for design, location, and operation required by various government agencies. Recognizing the importance of nuclear power and its many environmental and economic benefits, the Company continues to develop an additional unit at North Anna. For further discussion of the Company's development of North Anna 3, see Section 5.3. This resource was considered for further analysis in the Company's busbar curve analysis.

Nuclear Fusion

Electric power from nuclear fusion occurs from heat energy generated from a nuclear fusion reaction. The Company will continue to monitor any developments regarding nuclear fusion technology. This resource was not considered for further analysis in the Company's busbar curve analysis.

Small Modular Reactors ("SMRs")

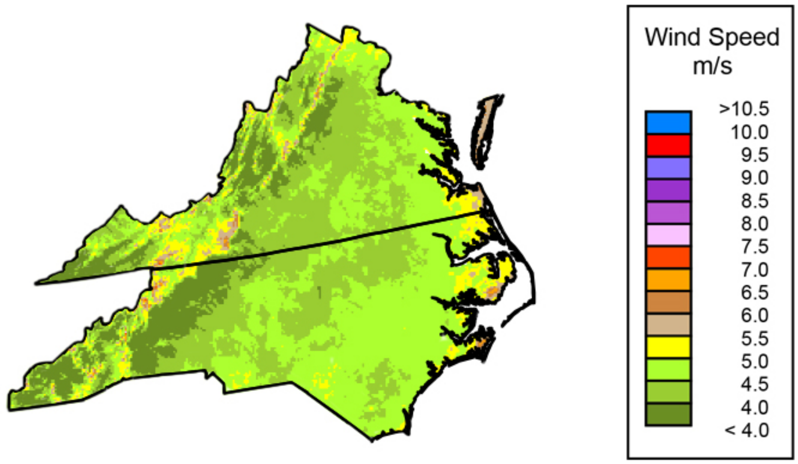
SMRs are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured almost entirely off-site in factories and delivered and installed on site in modules. The small power output of SMRs equates to higher electricity costs than a larger reactor, but the initial costs of building the plant are significantly reduced. An SMR entails underground placement of reactors and spent-fuel storage pools, a natural cooling feature that can continue to function in the absence of external power, and has more efficient containment and lessened proliferation concerns than standard nuclear units. SMRs are still in the early stages of development and permitting, and thus at this time are not considered a viable resource for the Company. The Company will continue to monitor the industry's ongoing research and development regarding this technology. This resource was not considered for further analysis in the Company's busbar curve analysis.

5.1.2 NON-DISPATCHABLE RESOURCES

Onshore Wind

Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals and REPS requirements, Clean Power Plan requirements, and also as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. There is limited land available in the Company's service territory with sufficient wind characteristics because wind resources in the Eastern portions of the United States are limited and available only in specialized locations, such as on mountain ridges. Figure 5.1.2.1 displays the onshore wind potential of Virginia and North Carolina. The Company continues to examine onshore wind and has identified three feasible sites for consideration as onshore wind facilities in the western part of Virginia on mountaintop locations. This resource was considered for further analysis in the Company's busbar curve analysis.

Figure 5.1.2.1 - Onshore Wind Resources

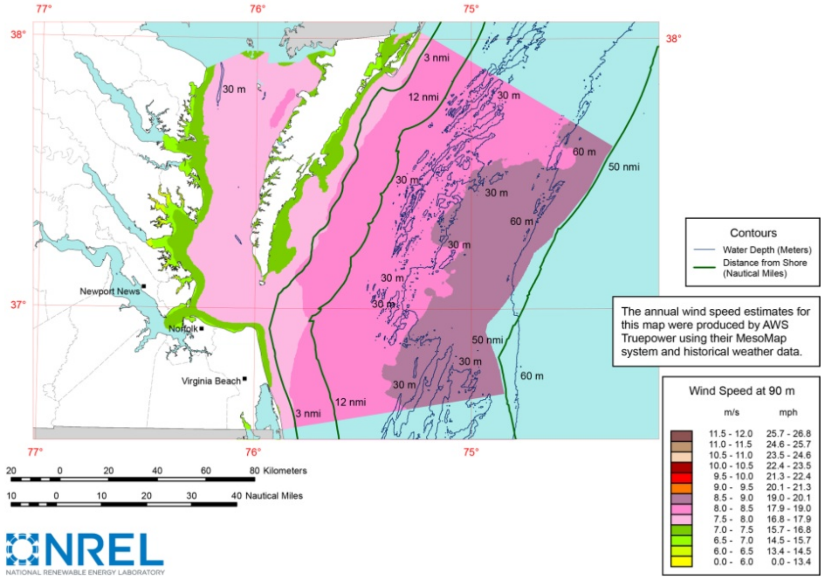


Source: National Renewable Energy Laboratory on April 29, 2016.

Offshore Wind

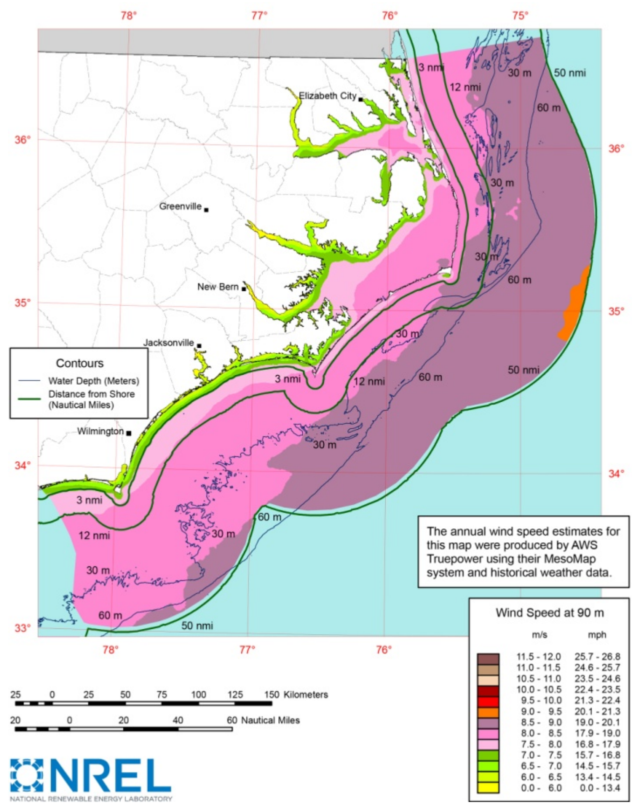
Offshore wind has the potential to provide a large, scalable renewable resource for Virginia. Figures 5.1.2.2 and 5.1.2.3 display the offshore wind potential of Virginia and North Carolina, respectively. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending approximately 40 miles off the coast, proximity to load centers, availability of local supply chain infrastructure, and world class port facilities. However, one challenge facing offshore wind development is its complex and costly installation and maintenance when compared to onshore wind. This resource was considered for further analysis in the Company's busbar curve analysis.

Figure 5.1.2.2 - Offshore Wind Resources - Virginia



Source: Retrieved from U.S. Department of Energy on April 29, 2016.

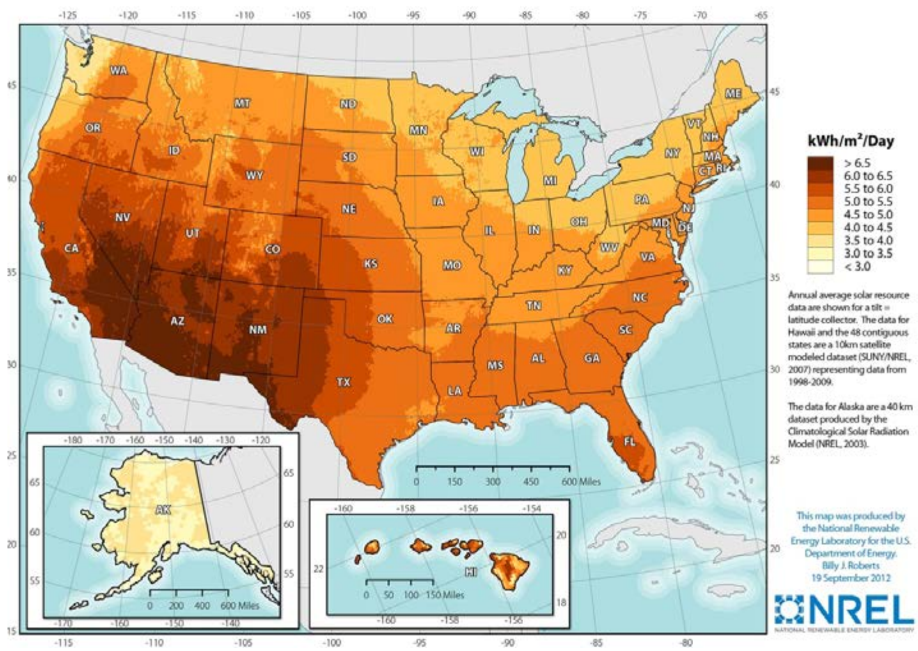
Figure 5.1.2.3 - Offshore Wind Resources – North Carolina



Source: Retrieved from U.S. Department of Energy on April 29, 2016.

Solar PV & Concentrating Solar Power ("CSP")
Solar PV and CSP are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that use semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large-scale solar plants and are mostly found in the southwestern area of the United States where solar resource potential is the highest. Figure 5.1.2.4 shows the solar PV resources for the United States.

Figure 5.1.2.4 – Solar PV Resources of the United States



Source: National Renewable Energy Laboratory on April 29, 2016.

Solar PV technology was considered for further analysis in the Company's busbar curve analysis, while CSP was not. The Company has considered both fixed-tilt and tracking PV technology. Also included in the Company's analysis is a fixed-tilt solar PV unit at a brownfield site (e.g., solar at an existing facility, solar tag at a new CC site). By installing solar at an existing generating facility, the output can be tied into the existing electrical infrastructure. Use of such a site would allow the Company to decrease the initial fixed cost of the resource, while the other characteristics of the unit stay the same. The Company currently has several solar PV facilities under development, including Scott 17 MW (nameplate), Whitehouse 20 MW (nameplate), and Woodland 19 MW (nameplate).

Solar generation is intermittent by nature, which fluctuates from hour-to-hour and in some cases from minute-to-minute. This type of generation volatility on a large scale could create distribution and/or transmission instability. In order to mitigate this anomaly, other technologies may be needed, such as battery technology, quick start generation, voltage control technology, or pumped storage. The planning techniques and models currently used by the Company do not adequately assess the operational risk that this type of generation could create, as further explained in Section 5.1.2.1.

HB 2237

In its 2015 Session, the Virginia General Assembly enacted HB 2237, which declared utility-scale solar with an aggregate rated capacity of up to 500 MW and located in the Commonwealth to be in the public interest. Additionally, utilities are allowed to enter into short- or long-term power purchase contracts for solar power prior to purchasing the generation facility. Pursuant to this legislation, a utility seeking approval to construct or purchase such a facility that utilizes goods or services sourced from Virginia businesses may propose a RAC based on a market index rather than a cost of service model. As part of its recent request that the SCC issue a CPCN for 56 MW of 2016 Solar Projects (Case No. PUE-2015-00104), the Company filed for approval for Rider US-2, which is based on a market index cost recovery. As noted in the Company's pre-filed testimony in that case, the Company determined after an RFP process that the market index provided better economic value for customers than a traditional cost of service. The Company will continue to consider both market index and cost of service models for future projects in determining which approach is in the best interest of customers.

5.1.2.1 SOLAR PV RISKS AND INTEGRATION

Photovoltaic (PV) generation systems are quite different from traditional supply-side resources like coal, nuclear, and natural gas-fired power plants. All levels of the existing electric infrastructure, standards and operating protocols were originally designed for a dispatchable generation fleet (based on the market price as well as the topological condition of the electric network). This paradigm ensures system stability through control of frequency and voltage. PV generation systems, in contrast, only produce electricity when the sun is shining; therefore, energy output is variable and cannot be dispatched. Another important difference is that traditional generation facilities are operated at utility-scale, while a significant portion of existing and anticipated future solar installations are installed by the end user (e.g., a homeowner, business, or other non-utility entity) – often mounting the PV panels on the roof of a building or on smaller scale developer-built sites tied into a distribution circuit. Because of this paradigm shift, power may be injected either at the transmission level at on the distribution level. Therefore, the electrical grid is evolving from a network where power flows from centralized generators through the transmission network and then to distribution systems down to the retail customer, into a network with generators of many sizes introduced into every level of the grid. The overall result is that traditional assumptions about the direction of power flows are no longer valid.

Solar PV Integration Considerations

Even though solar PV and other renewable energy technologies are poised to provide a measurable share of this nation's electricity supply, there are increasing industry concerns regarding the potential impacts of high-penetrations of solar PV on the stability and operation of the electric grid. Of particular concern is the intermittent availability of solar energy associated with rapidly changing cloud cover, which results in variable power injections and losses on the grid, impacting key network parameters, including frequency and voltage. During grid disturbances, decentralized generation such as PV is expected to disconnect and subsequently reconnect once the grid normalizes. While the grid may not be adversely impacted by the small degree of variability resulting from a few distributed PV systems, larger levels of penetration across the network or high concentrations of PV in a small geographic area may make it difficult to maintain frequency and voltage within acceptable bands. On a multi-state level, it is possible that the resulting sudden power loss from disconnection of distributed PV generation could be sufficient to destabilize the system frequency of the entire Eastern Interconnection. Along those same lines, simultaneous reconnection of the distributed PV generation during frequency recovery may lead to excessive frequencies, which could cause the various PV systems to disconnect, or "trip," again.

To address such unfavorable impacts on the electric grid, power system components such as voltage regulators and transformer tap changers are beginning to be required to operate at levels inconsistent with their original design. Power quality is an additional concern due to the supply of energy to the grid through DC to AC converters, which can introduce, in aggregate, unacceptable harmonics levels into the grid. Increased harmonics are harmful because they can induce premature aging and failure of impacted devices. Addressing these and other grid integration issues is a necessary prerequisite for the long-term viability of PV generation as an alternative energy resource.

Mitigation Devices and Techniques

Newer technologies, such as static synchronous compensators ("STATCOMs"), are designed to help prevent certain undesirable operating conditions on the electric grid – particularly abnormal or rapidly varying voltage conditions. For example, Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547, which was developed pursuant to the Energy Policy Act of 2005, provides a uniform standard for interconnection of distributed resources with electric power systems, including requirements relevant to the performance, operation, testing, safety consideration and maintenance of the interconnection. In accordance with that standard, PV inverters, which invert the DC output of a solar PV facility into AC, continuously monitor the grid for voltage and frequency levels. The PV-grid interconnection standards currently adopted by most utilities require that PV systems disconnect when grid voltage or frequency varies from specified levels for specified durations. If multiple PV systems detect a voltage disturbance and disconnect simultaneously, then a sharp reduction in generation may occur, potentially further exacerbating the voltage disturbance. A reverse effect can be observed following a corrective response to a voltage or frequency perturbation. After an event is resolved, simultaneous ramping of multiple solar PV systems may also induce grid disturbances. To alleviate such voltage flicker and other power quality issues, distribution STATCOMs may be employed at the interface between the grid and renewable energy source. Furthermore, STATCOM applications can serve as an effective method for real power exchange between distribution load, the electric grid, and PV systems. Such devices have traditionally been relegated to niche applications and can be costly.

To address the intermittency and non-dispatchable characteristics of solar generation resources, the need for co-located power storage is paramount. PV DC-to-AC inverters may enable the integration of a battery or other energy storage device with distributed generators. When active power is produced by the generator, the inverter will provide the power to the grid, but the inverter may also allow the active power to be stored if it is not needed at that moment. Therefore, the stored power can be dispatched by the grid while maintaining the operational stability of the electric grid. In the case of utility interconnected inverters, pricing signals may be employed in the future to autonomously activate the charging or discharging modes of the storage device. Energy storage represents a useful capability with regards to the intermittency of many forms of distributed generation, particularly those which rely on solar or wind power. At present, the adoption of storage technologies has inherent challenges due to cost-effectiveness, reliability, and useful life.

As deployment of PV generation increases, suitable control strategies must be developed for networks with a high penetration of DG to modulate the interactions between the transmission and distribution systems. Infrastructure improvements and upgrades will be explored to address the impact of the substantial distributed energy flows into the utility grid. Most of these impact studies are based upon simulations, so adequate static and dynamic models for DG units are required. Many technical aspects and challenges related to PV inverters still need to be properly understood and addressed by the industry to produce adequate models for the study of these devices and their impact on system stability and control.

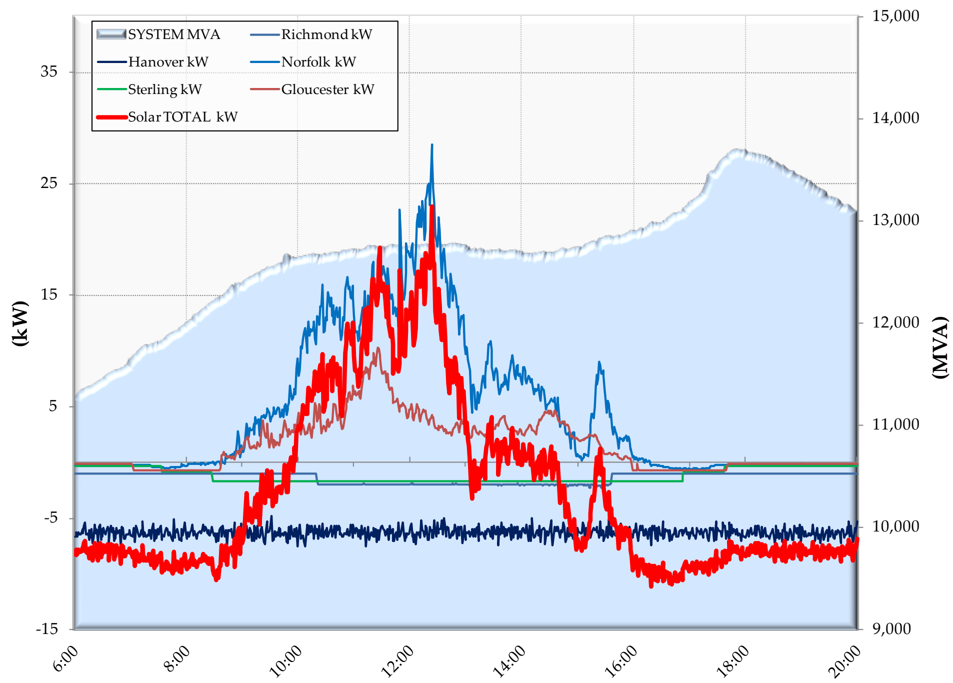
Communications Upgrades

Communications infrastructure is an integral component for successful integration of PV and other intermittent renewable resources onto the electric grid. Communications upgrades also introduce additional capital and operations costs. As DG sites increase in number, communication with the transmission and distribution control centers will be essential for ensuring safe and reliable grid operation. Providing secure communications between monitoring, protection, and control systems spanning long distances will be required to facilitate overall system reliability. The two major facets of operations that are impacted by the availability of adequate high speed communication are monitoring and control. The impacts on the bulk electric system caused by increasing intermittent generation should be monitored via high resolution meters, such as synchrophasors and digital fault recorder devices. These devices are placed at the point of interconnection and would support high speed tripping to address power quality concerns (harmonics, voltage, etc.). As mentioned earlier, PV inverters monitor power system parameters and disconnect when those parameters deviate from the ranges specified in IEEE Standard 1547 in order to prevent island conditions. This capability is called anti-islanding control. With the increase of interconnected inverters, the variety of different manufacturers' inverters increases as well. Despite state regulation encouraging standardized inverters, since all of these inverters use different algorithms to detect islands, a more comprehensive method is needed to ensure that inverters will disconnect when required, in addition to being able to ride-through certain system conditions. Communications infrastructure needs to facilitate disconnection of these distributed generators in a rapid (less than one second) and highly reliable manner.

PV technology is a promising technology and is becoming more economically favorable for energy production. However, significant room for improvement remains for network integration – a prerequisite to becoming a realistic alternative to traditional generation. These improvements include, but are not limited to, cost reduction and increased lifespan for advanced integrated inverter/controller hardware, integrated high speed fiber communication, efficient and strategically located energy storage devices, modern engineering analysis techniques, and upgrades to existing facilities.

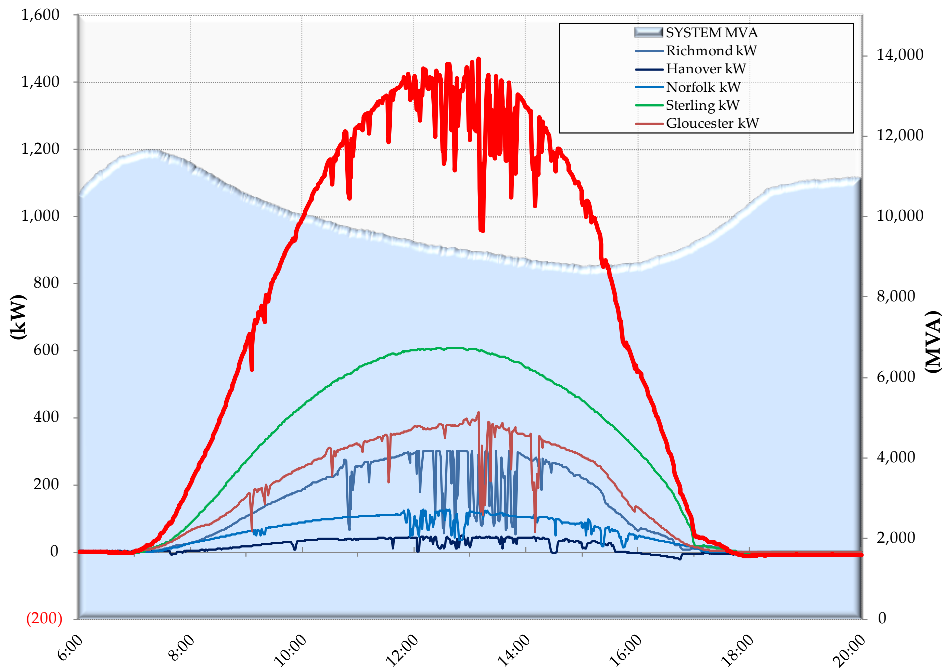
Summary
In summary, the anticipated future growth of solar PV energy generation may result in significant challenges to the Company's distribution system as well as the larger bulk electric system. Whether powered from utility-scale facilities or distributed generation sources, the industry needs an understanding of the critical threshold levels of solar PV where significant system changes must occur. The nature and estimated costs of those changes are still unknown at this stage, but these costs, particularly at the higher penetration levels, could be substantial. In a July 2015 filing with the California Public Utilities Commission, Southern California Edison estimated capital expenditures in the range of $1.4 - $2.5 billion necessary to upgrade its current grid to facilitate integration of high levels of distributed generation resources, which are expected to be made up of mostly solar PV. As solar pilots and study results become available, more information regarding integration costs and the Company's deployment strategies necessary to support large volumes of solar PV generation will be incorporated into future integrated resource plans. For this 2016 Plan, however, a proxy cost estimate as described in Chapter 4 was utilized. Figures 5.1.2.1.1 and 5.1.2.1.2 show the intermittent nature of solar recorded values of the Company's Solar Partnership Program and the shape of the production curve relative to the demand curve.

Figure 5.1.2.1.1 – SPP Actual Meter Readings in Virginia – Snowy Day – January 23, 2016



Note: As shown in the graph, the negative output condition is due to temperature control equipment operation for the integrated battery systems and panel heating during cold weather and when solar output of small facilities was at low or zero output due to local weather conditions.

Figure 5.1.2.1.2 – SPP Actual Meter Readings in Virginia – Sunny Day – February 18, 2016



Virginia Solar Pathways Project
The Company and a partnership team were selected to receive a three-year award for up to $2.5 million from the U.S. Department of Energy ("DOE") to assist in expanding solar generation in Virginia. The funding will be used to develop a utility-administered solar strategy for the Commonwealth of Virginia through technical solar studies and collaboration with a partnership team comprised of key solar stakeholders.

The Company's partnership team consists of:

- Virginia Department of Mines, Minerals, and Energy;
- City of Virginia Beach;
- Old Dominion University;
- Metro Washington Council of Governments;
- Bay Electric Co., Inc.;
- Piedmont Environmental Council;
- Virginia Community College System; and
- National Renewable Energy Laboratory ("NREL").

Technical Studies
As part of the project, NREL completed a solar economic study that included a survey of local solar installers and provided recommendations for reducing the non-hardware costs ("soft costs") of implementing solar.

Additionally, the Company procured third-party consultants to perform a series of solar integration studies. These initial solar integration studies, which were conducted under "Phase I" of the Virginia Solar Pathways Project, set the foundation for the analysis of the Company's generation, transmission, and distribution systems to provide operational recommendations for widespread integration of solar and the associated costs of these recommendations.

These Virginia Solar Pathways Project Phase I Studies, which were completed in March 2016, provided a valuable initial step toward identifying classifications of network violations that may be expected with increased solar penetration including, an analysis of a handful of PV distribution cases and a few specific mitigation strategies for any identified issues. This effort generated an abundance of useful information along with new planning tools that may be used in the future. For example, the studies identified areas in the Company's system with greater potential to accommodate PV generation and the main advantages of utilizing reactive power support from these sites.

Further Analysis

Consistent with the 2015 Plan Final Order, which directs the Company to develop a plan for identifying, quantifying and mitigating cost and integration issues associated with greater reliance on solar PV generation, "Phase II" of the Virginia Solar Pathways Project will build on the results from Phase I by providing a more in-depth analysis on expected costs and system upgrades, as discussed in more detail below. The Phase II studies are expected for completion in 2017.

Key dimensions to be addressed by the Phase II Studies include the following:

- assessment of dynamic voltage security margins, which provide the lower and upper range of pre-determined voltage levels within which the Company operates that may be impacted by variable power injections and losses resulting from the intermittent availability of solar PV;
- transient stability assessments with and without dynamic inverter grid support functionalities; and
- a thorough grid frequency response analysis that contemplates possible degradations in system inertia as conventional synchronous generation is displaced.

In addition to these key dimensions, it is of utmost importance to better understand the additional costs associated with the engineering and technology that will need to be applied to the electric grid to prudently integrate this form of variable, non-dispatchable, inverter-based generation. The ultimate goal of understanding the total additional costs of PV integration is to appropriately and responsibly manage the costs of mitigating a broad range of technical challenges, the scope of which may only become evident as solar PV reaches higher penetration levels.

Analyzing the impact of PV to the overall power system is a complex task without precedent – one that, to properly execute, requires a methodology that is able to contemplate a multi-dimensional problem. Typical generation interconnection and integration studies are discrete analyses that are performed based upon the generation size and location of the generation in the bulk electric system. Based upon this specific information, measures to mitigate adverse system impacts are identified.

With that said, studying system-wide impacts of variable, non-dispatchable, inverter-based generation sources requires a more generic approach. This generic approach should involve multiple scenarios that rely on assumptions about multiple state-wide PV development scenarios. Due to the uncertainty of PV integration, answers to the most important questions must be determined statistically from large sample sets with a probability distribution of potential outcomes. Since it is not feasible to determine the exact nature of all technical network violations, the study must aim to answer questions in a broader, more holistic way.

As generation interconnection requirements evolve to enable necessary control and to incorporate multiple modes of operation of solar PV generation, communication to and from these sites will be crucial to maintain coordination with other grid supporting elements such as transformers Load Tap Changers (“LTCs”), voltage regulators, capacitor banks, and Flexible Alternating Current Transmission System (“FACTS”) devices. Larger levels of PV penetration may require centrally dispatched control of inverter set-points, schedules, ramp-rates, control modes, and other advanced grid support functions. This should be viewed as an enabler for greater levels of PV penetration, but there is, however, a cost associated with this enabling flexibility.

The impacts of high-penetration solar PV on the Company’s distribution system must be evaluated in a probabilistic manner as well. The Virginia Solar Pathways Project was able to demonstrate, via scenario analysis, that variable power losses (associated with rapidly changing cloud cover) have an adverse effect on dynamic voltage performance of the Company’s distribution network. The study also offers examples of how to improve this performance by using inverter-based grid support functionalities, STATCOMs, and energy storage. However, an in-depth dynamic stability analysis is required to evaluate the impact on voltage and frequency in the distribution system to determine the PV penetration level at which either voltage and/or frequency ride-through (LVRT/LFRT) functionalities of PV inverters are necessary to avoid broader grid disturbances. Similar scenarios can occur with voltage disturbances. The Virginia Solar Pathways Project Phase II Studies will address the effects of large transmission disturbances on PV connected at the distribution level and how those effects can be detrimental to overall system health, which were not addressed in Phase I.

Conclusion
With current technology, Virginia’s potential maximum solar build out is relatively small compared to other states in the U.S. and countries in the world. Information on the development, integration and analytics regarding more extensive and intensive solar PV installations is not available to the industry or the Company for the 2016 Plan. Under Phase II of the Virginia Solar Pathways Project, the Company will continue developing its plan for identifying, quantifying and mitigating cost and integration issues associated with greater reliance on solar PV generation, while also building on the results from Phase I through additional studies and analyses described in this section.

5.1.3 ASSESSMENT OF SUPPLY-SIDE RESOURCE ALTERNATIVES

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of the alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the

Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource was able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand requirements. Further, this portion of the analysis requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel, operation and maintenance. Figure 5.1.3.1 summarizes the resource types that the Company reviewed as part of this IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 5.1.3.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource
Aero-derivative CT	Peak	Yes	Natural Gas	No
Biomass	Baseload	Yes	Renewable	Yes
CC 1x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 2x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 3x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CFB	Baseload	Yes	Coal	No
Coal (SCPC) w/ CCS	Intermediate	Yes	Coal	Yes
Coal (SCPC) w/o CCS	Baseload	Yes	Coal	Yes
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes
Geothermal	Baseload	Yes	Renewable	No
Hydro Power	Intermittent	No	Renewable	No
IGCC CCS	Intermediate	Yes	Coal	Yes
IGCC w/o CCS	Baseload	Yes	Coal	Yes
Nuclear	Baseload	Yes	Uranium	Yes
Nuclear Fusion	Baseload	Yes	Uranium	No
Offshore Wind	Intermittent	No	Renewable	Yes
Onshore Wind	Intermittent	No	Renewable	Yes
Solar PV	Intermittent	No	Renewable	Yes
Solar PV with Battery	Peak	Yes	Renewable	Yes
SMR	Baseload	Yes	Uranium	No
Tidal & Wave Power	Intermittent	No	Renewable	No

The resources not included as busbar resources for further analysis faced barriers such as the feasibility of the resource in the Company's service territory, the stage of technology development, and the availability of reasonable cost information.[15] Although such resources were not considered in this 2016 Plan, the Company will continue monitoring all technologies that could best meet the energy needs of its customers.

15 See www.epri.com for more information on confidence ratings.

Third-Party Market Alternatives to Capacity Resources

Solar

During the last two years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territory. On July 22, 2015, the Company issued an RFP for new utility-scale solar PV generating facilities, located in Virginia, which could achieve an online date of either 2016 or 2017. As a result of this RFP, the Company has executed two PPAs for approximately 40 MW and has an application pending before the SCC (Case No. PUE-2015-00104) for a CPCN to construct and operate three self-build solar facilities (Scott, Whitehouse and Woodland) totaling approximately 56 MW. The Company has proposed to recover the cost of these facilities through a market index rate of $55.66/MWh escalated at 2.5% for 20 years, which matches the capacity-weighted average price of the short-listed PPAs from the RFP. Additionally, the Company is still evaluating RFP proposals for Virginia-based 2017 COD projects.

In North Carolina, over the same period, the Company signed 56 PPAs totaling approximately 384 MW (nameplate) of new solar NUGs. Of these, 218 MW are from 30 solar projects that are currently in operation as of March 2016. The majority of these developers are Qualifying Facilities ("QFs"), contracting to sell capacity and energy at the Company's published 2012 North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act ("PURPA"), as approved in Docket No. E-100, Sub 136 and Docket No. E-100, Sub 140.

Wind

In the past two years, the Company has evaluated approximately 310 MW of onshore wind third-party alternatives, none of which were located in Virginia. While these projects would be less expensive than the Company's self-build wind options (both onshore and offshore), they were not competitive against new gas-fired generation and at the time of evaluation, were not expected to contribute toward the Commonwealth meeting its CPP requirements and therefore were rejected.

Other Third-Party Alternatives

Over the past two years, the Company has evaluated a number of opportunities to extend the contracts of the current NUG contracts that have recently expired or will expire in the next several years. Many of these were evaluated through a formal RFP process while others were evaluated through direct contact with the existing NUG owner. However, none were found to be cost-effective options for customers when compared to other options, such as the Greensville County Power Station. Additionally, the Company has been in early discussions with a number of developers of other new third-party generation alternatives over the past year. However, none of these discussions have matured to the point of the Company receiving or being able to evaluate a firm PPA price offer.

5.2 LEVELIZED BUSBAR COSTS

The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed operation and maintenance ("O&M") costs, expected service life, and overnight construction costs.

Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.1 and 5.1.2. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

Consistent with the 2015 Plan, the Company has included a solar PV facility coupled with a battery ("solar PV/battery facility") as an entry to the dispatchable busbar curve analysis. At a zero capacity factor, the cost of a solar PV/battery facility is approximately $1,000/kW-year higher than a solar PV facility alone. This difference represents the proxy cost of making a solar PV facility dependable and dispatchable. Given recent advancements in battery technology, the Company expects that batteries will be a viable option for consideration in future integrated resource plans and, as such, deems it appropriate to begin reflecting that option in the busbar curve analysis.

Figure 5.2.1 - Dispatchable Levelized Busbar Costs (2022 COD)

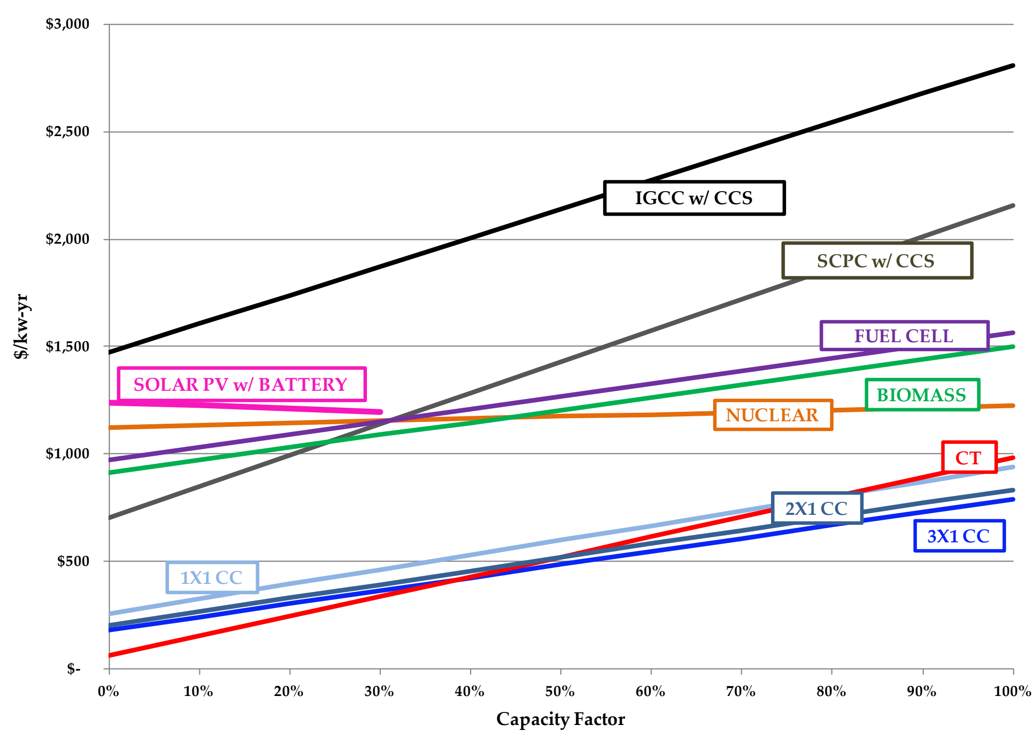
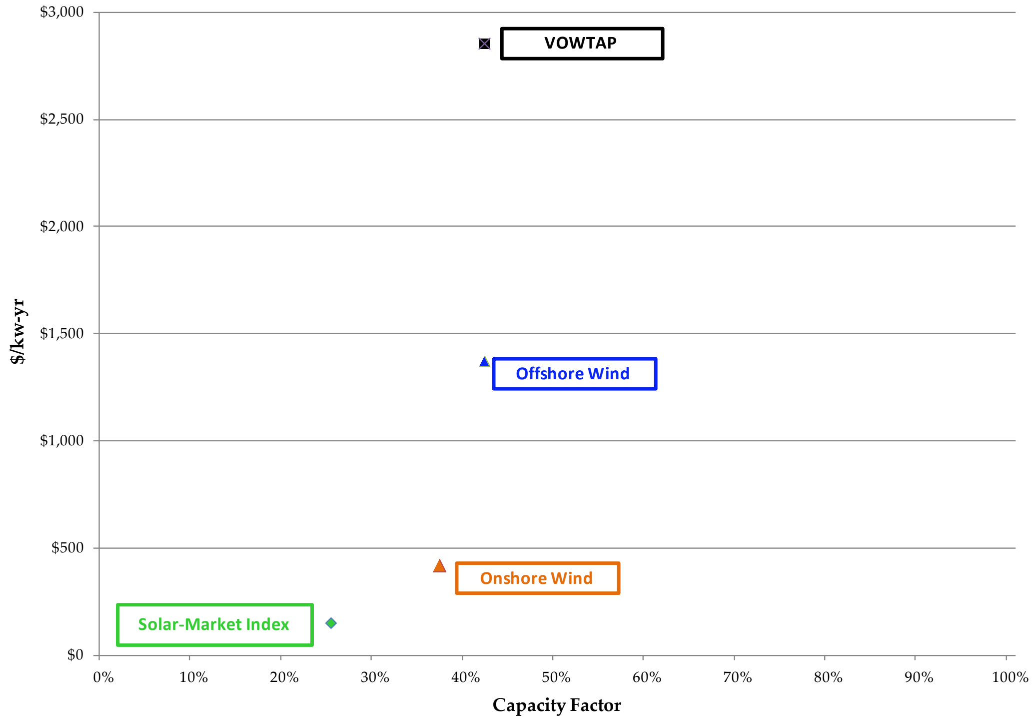


Figure 5.2.2 - Non-Dispatchable Levelized Busbar Costs (2022 COD)



Appendix 5A contains the tabular results of the screening level analysis. Appendix 5B displays the heat rates, fixed and variable operation expenses, maintenance expenses, expected service lives, estimated 2015 real dollar construction costs, and the first year economic carrying charge.

In Figure 5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with busbar costs above the lowest combination of curves generally fail to move forward in a least cost resource optimization. Higher cost generation, however, may be necessary to achieve other constraints like those required under the CPP. Figures 5.2.1 and 5.2.2 allow comparative evaluation of resource types. The cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of the unit, including fuel, emissions, and any REC value a given unit may receive.

As shown in Figure 5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 35% for meeting the Company's peaking requirements. Currently, the CC 3x1 technology is the most economical option for capacity factors greater than approximately 35%.

Nuclear units have higher total life-cycle costs than a CC 3x1; however, they operate historically at higher capacity factors and have relatively more stable fuel costs and operating costs. Fuel also makes up a smaller component of a nuclear unit's overall operating costs than is the case with fossil fuel-fired units. New coal generation facilities without CCS technology will not meet the emission limitation included in the EPA's GHG NSPS rule for new electric generating units.

Wind and solar resources are non-dispatchable with intermittent production, limited dispatchability, and lower dependable capacity ratings. Both resources produce less energy at peak demand periods, therefore more capacity would be required to maintain the same level of reliability. For example, onshore wind provides only 13% of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4. Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. In addition, intermittent resources may require additional grid equipment and technology changes in order to maintain grid stability as described in Section 5.1.2.1. The Company is routinely updating and evaluating the costs and availability of renewable resources, as discussed in Section 5.4.

Figure 5.2.3 identifies some basic capacity and energy differences between dispatchable resources and non-dispatchable resources. One additional factor to consider for solar installation is the amount of land required. For example, the installation of 1,000 MW of solar requires 8,000 acres of land.

Figure 5.2.3 - Comparison of Resources by Capacity and Annual Energy

Resource Type	Nameplate Capacity (MW)	Estimated Firm Capacity (MW)	Estimated Capacity Factor (%)	Estimated Annual Energy (MWh)
Onshore Wind	1,000	130	42%	3,696,720
Offshore Wind	1,000	167	42%	3,635,400
Solar PV[1]	1,000	587	25%	2,198,760
Nuclear	1,000	1,000	96%	8,409,600
Combined Cycle (3x1)	1,000	1,000	70%	6,132,000
Combustion Turbine	1,000	1,000	10%	876,000

Note: 1) Solar PV firm capacity has zero percent value in the first year of operation and increases gradually to 58.7% through 15 years of operation.

The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime. Further analysis was conducted in Strategist to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This simulation analysis further refines the analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

Extension of Nuclear Licensing

An application for a second license renewal is allowed during a nuclear plant's first period of extended operation - i.e., in the 40-60 years range of its service life. Surry Units 1 and 2 entered into that period in 2012 (Unit 1) and 2013 (Unit 2), however, North Anna Units 1 and 2 will not enter into that period until 2018 (Unit 1) and 2020 (Unit 2).

The Company has informed the Nuclear Regulatory Commission ("NRC") in a letter dated November 5, 2015, attached as Appendix 3Y, of the intent to submit a second license renewal application for Surry Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," by the end of the first quarter of 2019. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2022 timeframe.

Although the Company has participated in public industry meetings during the last 12 months with other potential utility applicants in which second license renewal applications have been discussed with the NRC, there has been no additional correspondence between the Company and the NRC concerning any second license renewals.

NRC draft guidance on the requirements for a second license renewal was issued for public comment in December 2015. The industry, including the Company and interested stakeholders, has reviewed the guidance information to further understand the pre-decisional technical requirements and additional aging management program requirements. The nuclear industry, including the Company, provided comments through the Nuclear Energy Institute in February 2016, which was the end of the public comment. The NRC is currently evaluating the industry and stakeholder comments. The approved second license renewal guidance documents are scheduled for issuance in mid-2017. Following the issuance of the final NRC guidance documents, the Company will begin finalizing the technical evaluation and additional aging management program requirements required to support the second license renewal application.

The cost estimates for the extension of the nuclear licenses for Surry Units 1 and 2, as well as North Anna Units 1 and 2 can be found in Appendix 5H.

5.3 GENERATION UNDER DEVELOPMENT

North Anna 3

The Company is in the process of developing a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia, subject to obtaining all required approvals. Based on the expected schedule for obtaining the Combined Operating License ("COL") from the NRC, the SCC certification and approval process, and the construction timeline for the facility, the earliest possible in-service date for North Anna 3 is now September 2028, with capacity being available to meet the Company's 2029 summer peak. This in-service date has been delayed one-year from the 2015 Plan.

The technology selection for North Anna 3 is the General Electric-Hitachi ("GEH") Economic Simplified Boiling Water Reactor ("ESBWR"). In July 2013, the Company submitted a revised COL application to the NRC to reflect the change in technology from the Mitsubishi Heavy Industries Advanced Pressurized Water Reactor that was identified in the 2012 Plan. This decision was based on a continuation of the competitive procurement process that began in 2009 to find the best solution

to meet its need for future baseload generation. In October 2014, a major milestone was achieved when the NRC certified the ESBWR design for use in the United States.
In the 2015 Plan Final Order, the SCC directed the Company in this IRP filing to answer, inter alia, the following questions in relation to North Anna 3:

- Is there a dollar limit on how much Dominion intends to spend on North Anna 3 before applying for a CPCN and/or RAC?
- Without a guarantee of cost recovery, what is the limit on the amount of costs Dominion can incur, prior to obtaining a CPCN, without negatively affecting: (i) the Company's fiscal soundness; and (ii) the Company's cost of capital?
- Why are expenditures continuing to be made? Solely for NRC approval? Why in the Company's view is it necessary to spend at projected rates, specifically when the Company has not decided to proceed and does not have Commission approval?

Based on the timing of the evaluation and implementation of the CPP, the Company has determined it is prudent to focus its near-term efforts for North Anna 3 on the activities needed to secure the COL, currently expected to be issued by the NRC in 2017. By focusing on the COL activities and COL-related expenses, the Company is also slowing the spending for the additional engineering and other project development expenses related to the construction of North Anna 3. The Company continues the prudent development of North Anna 3 to provide certainty of cost, schedule, and ratepayer benefits should the project be submitted for CPCN approval. The Company will be open and transparent on the specific development cost, the total project forecast, and the potential benefits. In addition, the Company is mindful of risk associated with this project and continues to evaluate the pace of development to ensure the Company's fiscal soundness based on market and regulatory circumstances.

This focus has several benefits to customers because, (1) it will allow resources to focus on supporting the final reviews by the NRC for the COL; (2) current evaluation of the CPP shows that North Anna 3 is only selected as a resource in Plan E: Mass Emissions Cap (existing and new units), the most expensive of the four plans developed for compliance with the CPP in this IRP filing; (3) the CPP is currently stayed and the Commonwealth of Virginia's decision on the SIP is not yet available; and (4) the COL itself will be a valuable asset that will benefit the Company's customers.

Based on the above considerations, for IRP purposes, the North Anna 3 available capacity year will be moved back one year from 2028 to 2029, and spending will be reduced in the near term (2016/17), which will allow time for the CPP and COL process to evolve. The 2029 capacity year would support the option to develop North Anna 3 prior to the CPP compliance plan date of 2030, if warranted. As stated in the past, the Company will evaluate the timing of continued engineering and development activities for North Anna 3 once it has received the COL, which is currently expected in 2017. These actions will prudently pace development activities to current market conditions while continuing to preserve North Anna 3 as a viable resource option.

At the time of the issuance of the COL, the Company estimates that total expenditures associated with the development of North Anna 3 will be approximately $345 million (excluding AFUDC), which is net of the $302 million write-off applied to the capital development project and recovered through base rates as a result of Senate Bill 459, Virginia Acts of Assembly, 2014 Session, Chapter 541 (approved April 3, 2014; effective July 1, 2014) and as directed by the SCC's Final Order in the 2015 Biennial Review.

The Company has not quantified any particular dollar limit that it intends to incur for North Anna 3 before seeking recovery. Rather, the Company focuses on the reasonable and prudent development of any particular resource and achieving key developmental milestones related thereto. Once the Company secures the COL and after this period of added uncertainty regarding the CPP winds down, the Company will determine whether it will apply to the SCC for cost recovery and/or a CPCN. The Company stresses that its development efforts thus far for North Anna 3 have been prudent, and continuing to pursue the COL, a valuable asset with an indefinite life, is a reasonable and prudent decision. As stated above, by the time the COL is projected to issue in 2017, the Company estimates it will have spent approximately $345 million (excluding AFUDC), which is net of the $302 million write-off applied to the capital development project.

As the SCC has recognized on numerous occasions, and the Company has acknowledged, actual expenditures incurred toward any specific resource option that has not been approved by the Commission are incurred solely at the risk of the Company's stockholders.[16] Development of North Anna 3 is no different from other new resources in that every dollar spent by the Company without assurance of cost recovery increases the Company's risk profile, however incrementally. The Company believes that it has proceeded with the planning and development of North Anna 3 in a reasonable and prudent manner, and the associated planning and development costs are likewise prudent investments on the Company's part to ensure that this resource remains a viable option for customers in the future.

As noted previously, the Company stresses that its development efforts thus far for North Anna 3 have been prudent, and continuing to pursue the COL, a valuable asset with an indefinite life, is a reasonable and prudent decision. Once issued by the NRC, the COL is effectively an asset of the Company and its customers that remains in effect in perpetuity. This COL asset is not a hard asset but rather an option to build a nuclear unit at the North Anna site at some point in the future with no real expiration date. The Company maintains that an option such as this is of great value to customers given the uncertainty of the CPP and the uncertainty of any other federal or state law or regulation that the Company and its customers may face in the future. Expenditures are continuing to be made to secure the COL, and other expenditures related to construction of the unit have been slowed as discussed above.

Combined-Cycle

As described in Section 3.1.8, the Company issued an RFP on November 3, 2014, for up to approximately 1,600 MW of new or existing intermediate or baseload dispatchable generation

16 Application of Virginia Electric and Power Company For a 2015 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia, Case No. PUE-2015-00027, Final Order at 22 n.69 (Nov. 23, 2015); see also Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Case No. PUE-2011-00092, Order on Certified Question at 4 (Mar. 19, 2012).

located within the DOM Zone, or designated areas within an adjacent zone of PJM. The RFP requested PPAs with a term of 10 to 20 years, commencing in the 2019/2020 timeframe. Multiple proposals were received and evaluated. The Company's self-build CC in Greensville County provided superior customer benefits compared to all other options. The Greensville County CPCN was issued by the SCC, with a finding that the RFP was reasonable, on March 29, 2016.

Onshore Wind

The Company continues to pursue onshore wind development; however, there is a limited amount of onshore wind available within or near the Company's service territory. Only three feasible sites have been identified by the Company for consideration of onshore wind facilities. These sites are located in Virginia, on mountaintop locations.

Offshore Wind

The Company continues to pursue offshore wind development in a prudent manner for its customers and for the state's economic development. Offshore wind has the potential to provide a scalable renewable resource if it can be achieved at reasonable cost to customers. To help determine how this can be accomplished, the Company is involved in two active projects: 1) VOWTAP and 2) commercial development in the Virginia Wind Energy Area ("WEA"), both of which are located approximately 27 miles (~ 24 nautical miles) off the coast of Virginia. A complete discussion of these efforts is included in Section 5.4.

Solar PV

Three utility-scale solar PV facilities (Scott, Whitehouse and Woodland) totaling 56 MW are planned to be built in Powhatan County, Louisa County and Wight County, for which the Company filed for SCC approval and certification in Case No. PUE-2015-000104 on October 1, 2015. The facilities will be comprised of ground mounted, tracking solar panel arrays, which are a reliable, proven technology, and are expected to have an operating life of 35 years. The three facilities are expected to provide approximately 127 GWh of energy production at an average capacity factor of approximately 25% in the first full year of operation. These projects present a unique opportunity to take advantage of a favorable market for solar generation construction and operation, with the ability to bring the more advanced current solar technology online for the benefit of customers through the efficiencies of a utility-scale facility.

The Company has been involved with the SPP, which deploys solar facilities at customer sites throughout Virginia. As a result of this program, the Company is now assessing the generation data from these facilities and plans to use this information to assess how to properly integrate large volumes of this technology into the existing grid.

The Company is also actively pursuing development of 400 MW (including Scott, Whitehouse and Woodland facilities) of Virginia utility-scale solar projects in various locations throughout the Company's service territory. These projects are being phased in from 2016 - 2020.

Figure 5.3.1 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Capacity (Net MW)	
						Summer	Winter
2018	VOWTAP	VA	Wind	Intermittent	12	2	2
2020	VA Solar[2]	VA	Renewable	Intermittent	400	235	235
2029	North Anna 3	VA	Nuclear	Baseload	1,452	1,452	1,514

Notes: 1) All Generation under Development projects and capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals.
2) VA Solar is 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total). Solar PV firm capacity has zero percent value in the first year of operation and increases gradually to 58.7% through 15 years of operation.

Appendix 5C provides the in-service dates and capacities for generation resources under development.

5.4 EMERGING AND RENEWABLE ENERGY TECHNOLOGY DEVELOPMENT

The Company conducts technology research in the renewable and alternative energy technologies sector, participates in federal and state policy development on alternative energy initiatives, and identifies potential alternative energy resource and technology opportunities within the existing regulatory framework for the Company's service territory. The Company is actively pursuing the following technologies and opportunities.

Research and Development Initiatives – Virginia

Pursuant to Va. Code § 56-585.2, utilities that are participating in Virginia's RPS program are allowed to meet up to 20% of their annual RPS goals using RECs issued by the SCC for investments in renewable and alternative energy research and development activities. In addition to three projects completed in 2014, the Company is currently partnering with nine institutions of higher education on Virginia renewable energy research and development projects. The Company filed its third annual report in March 2016, analyzing the prior year's PJM REC prices and quantifying its qualified investments to facilitate the SCC's validation and issuance of RECs for Virginia renewable and alternative energy research and development projects.

As mentioned in Section 5.1.2.1, in 2015, the Company accepted a grant from the DOE for the purpose of funding the Virginia Solar Pathways Project. The project will engage a core advisory team made up of a diverse group of representatives. The ultimate goal for this project is to develop a collaborative utility-administered solar strategy for the Commonwealth of Virginia. The process will (i) integrate existing solar programs with new options appropriate for Virginia's policy environment and broader economic development objectives; (ii) promote wider deployment of solar within a low rate environment; and (iii) serve as a replicable model for use by other states with similar policy environments, including but not limited to the entire Southeast region.

Research and Development Initiatives – North Carolina

Pursuant to NCGS § 62-133.8(h), the Company completed construction of its microgrid demonstration project at its North Carolina Kitty Hawk District Office in July 2014. The microgrid project includes innovative distributed renewable generation and energy storage technologies. A microgrid, as defined by the DOE, is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, allowing it to operate in grid-connected or island mode. The project includes four different types of micro-wind turbines, a solar PV array, and a lithium-ion battery integrated behind-the-meter with the existing on-site diesel generator and utility feed. In the third quarter of 2015, the Company integrated two small, residential-sized fuel cells in order to study the fuel cell's interaction with the on-site renewable energy technologies in a microgrid environment. The knowledge gained from this microgrid project will be used to further assess the best practice for integrating large amounts of intermittent generation (such as wind and solar PV) into the existing grid.

Offshore Wind – Virginia

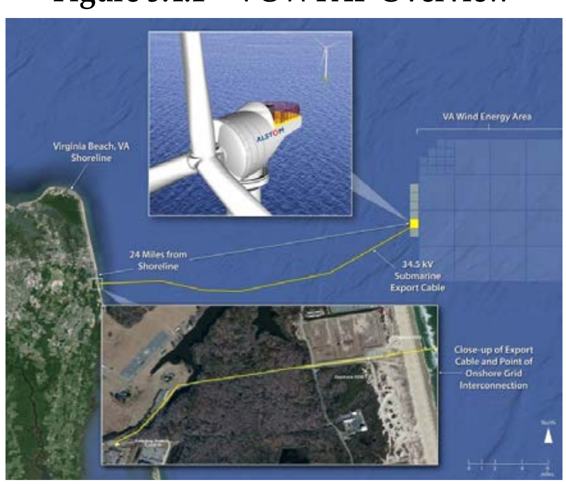
The Company is actively participating in offshore wind policy and innovative technology development in order to identify ways to advance offshore wind responsibly and cost-effectively. To that end, the Company is involved in the following select offshore wind policy and technology areas.

The Virginia General Assembly passed legislation in 2010 to create the Virginia Offshore Wind Development Authority ("VOWDA") to help facilitate offshore wind energy development in the Commonwealth. The Company continues to actively participate in VOWDA, as well as the Virginia Offshore Wind Coalition ("VOW"). The VOW is an organization comprised of developers, manufacturers, utilities, municipalities, businesses, and other parties interested in offshore wind. This group advocates on the behalf of offshore wind development before the Virginia General Assembly and with the Virginia delegation to the U.S. Congress.

The DOE awarded the Company $4 million in 2012 for VOWTAP to support the initial engineering, design, and permitting, plus up to an additional $47 million starting in 2014 for continued development toward construction. The proposed project will utilize two 6 MW GE/Alstom turbines which can help power up to 250 homes at peak demand.

Figure 5.4.1 illustrates the VOWTAP overview.

Figure 5.4.1 – VOWTAP Overview



In 2015, the Company announced a delay in the VOWTAP as it continued to work with stakeholders to find additional ways to reduce the cost and risks of this project. This delay was the result of significant increases in the estimated cost of the VOWTAP. The stakeholder process concluded the project was technically sound and an improved contract strategy could help lower the cost of installation. As a result of the stakeholder process, a second RFP for the VOWTAP project was issued; only this RFP was structured in a multi-contract manner (i.e., separate packages for marine supply, cable supply, fabrication, onshore electrical, etc.). This multi-consultant approach resulted in a lower overall bid cost of approximately $300 million. The Company and the DOE are currently reviewing the bids. The Company remains committed to the development of all renewable and alternative energy provided the development of these technologies is commercially viable and at a reasonable cost. In this 2016 Plan, the Company estimates that the on-line date for VOWTAP will be as early as 2018.

Energy Storage Technologies

In addition to the Bath County Pumped Hydro facility, the Company has been monitoring recent advancements in other energy storage technologies, such as batteries and flywheels. These energy storage technologies can be used to provide grid stability as more renewable generation sources are integrated into the grid. In addition to reducing the intermittency of wind and solar generation resources, batteries can shift power output from periods of low demand to periods of peak demand. This increases the dispatchability and flexibility of these resources.

Each type of energy storage device has different operational characteristics, such as duration, output, and round-trip efficiency. The Company recently installed a zinc-iron flow and an aqueous hybrid ion battery at a rooftop solar facility located at Randolph Macon College. These two small batteries are designed to test the extended capabilities of these new devices, and prove the potential benefits when integrated with existing solar generation.

Electric Vehicle (EV) Initiatives

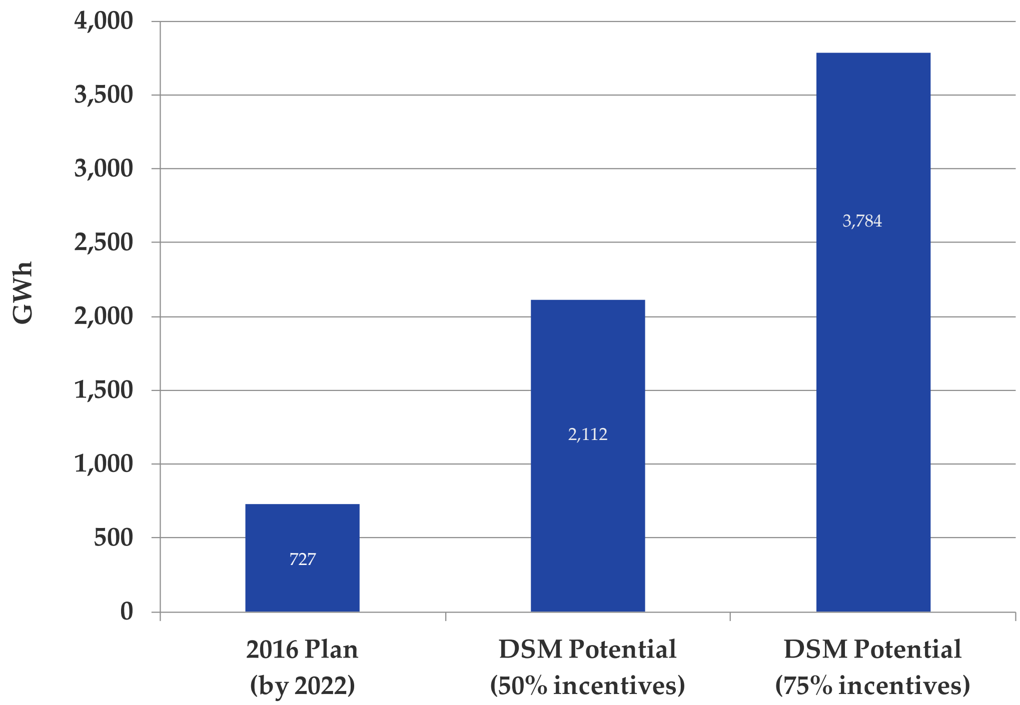
Various automotive original equipment manufacturers (“OEMs”) have released EVs for sale to the public in the Company’s service territory. The Chevrolet Volt, General Motor’s first plug-in hybrid electric vehicle (“PHEV"), and the Nissan Leaf, an all-electric vehicle, became available for sale in the Company’s Virginia service territory in 2011. Since that time, the Company has monitored the introduction of EV models from several other OEMs in its Virginia service territory. These include, but are not limited to, the Toyota Prius, the Ford Focus Electric and C-Max Hybrid Energi, the Tesla Roadster and Model S, and the Mitsubishi i-MIEV. While the overall penetration of EVs has been somewhat lower than anticipated, recent registration data from the Virginia Department of Motor Vehicles (“DMV”) and IHS, Inc. (formerly Polk Automotive) demonstrates steady growth. The Company used data from the Virginia DMV, Electric Power Research Institute (“EPRI”) and IHS, Inc. to develop a projection of system level EV and PHEV penetrations across its service territory to use in determining the load forecast used in this 2016 Plan.

5.5 FUTURE DSM INITIATIVES

In order to support approved DSM programs and identify measures that may be incorporated into future or current programs, the Company initiated a DSM Market Potential Study (“DSM Potential Study”) with DNV GL in 2013, the preliminary results of which the Company shared with stakeholders at its SRP meeting in November 2014. The DSM Potential Study consisted of three phases. Phase I was the appliance saturation survey, which was sent to a representative sample of residential and non-residential customers within the Company's service territory to assess the number of appliances within households and businesses, respectively. This survey was completed at the end of 2013.

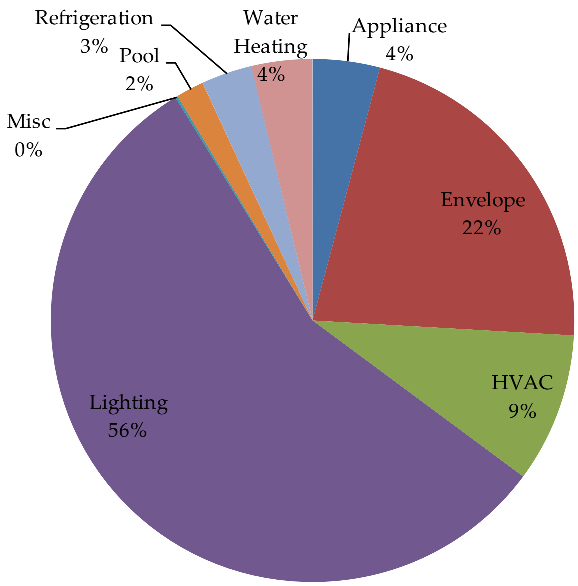
Phase II was the conditional demand analysis, during which the Company effectively developed a model to accurately identify the key end-use drivers of energy consumption for the Company's residential customers. This study was completed in May 2014. Phase III started with the development of baseline energy usage for all appliances within the residential and commercial sectors by building type. This baseline analysis was followed by the technical, economic, and achievable market potential of energy savings for all measures in the Company's residential and commercial sectors. The technical market potential reflects the upper limit of energy savings assuming anything that could be achieved is realized. Similarly, the economic potential reflects the upper limit of energy savings potential from all cost-effective measures. The achievable potential reflects a more realistic assessment of energy savings by considering what measures can be cost-effectively implemented through a future program. The result was a list of cost-effective measures that can ultimately be evaluated for use in future program designs and a high level estimate of the amount of energy and capacity savings still available in the Company's service territory. The achievable potential identified in the DSM Potential Study is shown in Figure 5.5.1.

Figure 5.5.1 – 2016 Plan vs. DSM System Achievable Market Potential



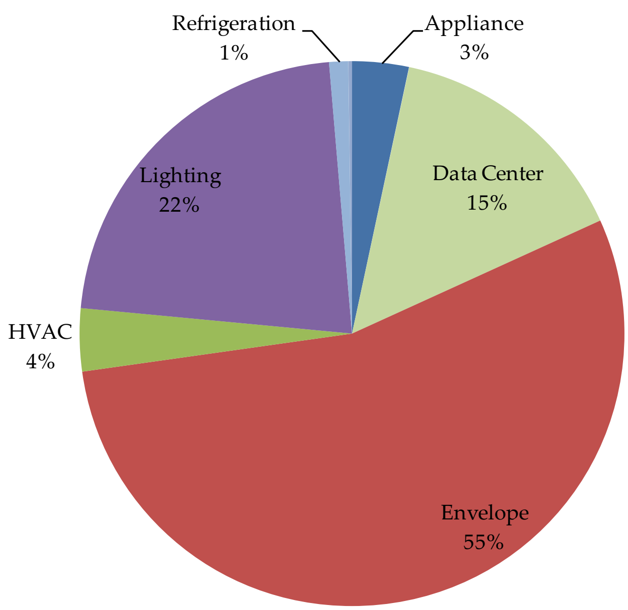
The Company also reviewed the measures included in the market potential study and compared them to the measures that were included in the DSM portfolio in the 2015 Plan. Figures 5.5.2 and 5.5.3 show the GWh potential by measure category for measures not included in the 2015 DSM portfolio for the Residential and Non-Residential classes. The Company is currently reviewing the measures not currently in approved or proposed programs, to determine how best to see if these measures can be incorporated into existing programs or new proposed programs. Because of the compressed time schedule for this IRP document, the Company was not able to fully develop projections for future modifications to existing programs or proposed future programs.

Figure 5.5.2 – Residential Programs – 50% Incentive Level



Measure	GWh
Appliance	40
Envelope	208
HVAC	88
Lighting	536
Misc	2
Pool	16
Refrigeration	30
Water Heating	36
Total	**957**

Figure 5.5.3 – Non-Residential Programs – 50% Incentive Level

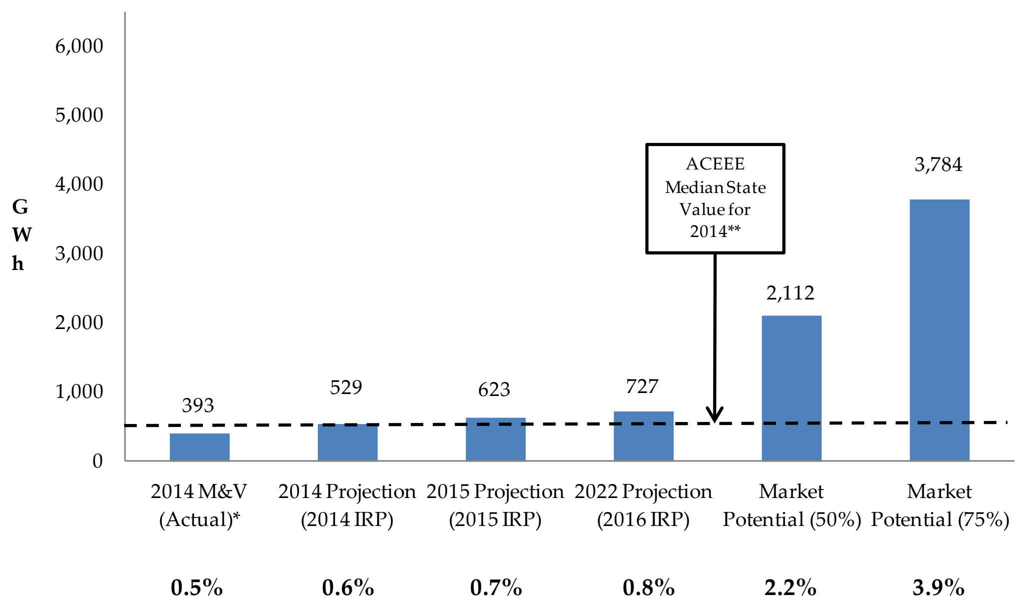


Measure	GWh
Appliance	4
Data Center	19
Envelope	70
HVAC	5
Lighting	28
Refrigeration	1
Water Heating	0
Total	**128**

The Company's Phase II DSM programs, which include the Residential Bundle (Residential Home Energy Check-up, Residential Duct Sealing, Residential Heat Pump Tune-up and Residential Heat Pump Upgrade) and the Commercial Bundle (Non-residential HVAC and Lighting), could potentially be redesigned taking into account the lessons learned from the experience with these programs over the last few years. These redesigns could include adding measures that are not currently offered in the existing programs, adjusting kW and kWh contribution assumptions per customer based on EM&V results and/or adjusting the penetration assumptions for the measures that are included in existing programs to more reasonable levels. This could increase some penetration assumptions or reduce them depending on the success that can be expected from the individual measures.

Figure 5.5.4 shows a comparison of the actual energy reductions for the year 2014 compared to the projected energy reductions for 2014. The actual energy reductions were 74% of the projected energy reductions for the year 2014. The energy reductions projected for 2022 in the 2015 Plan were 997 GWh. This level of energy reduction represents 47% of the amount shown in the Market Potential Study (50% incentive level) for the year 2022.

Figure 5.5.4 – DSM Projections/Percent Sales (GWh)



Note: *Actual energy savings are a function of SCC-approved program funding levels and measured energy savings/participation relative to program design projections.

**American Council for an Energy Efficient Economy (ACEEE) 2015 State Energy Efficiency Scorecard, page 31, Table 13, 2014 Net Incremental Savings by State, 0.56% median value applied to Company sales projections.

A reasonable approach is to examine the projected energy reductions as a percent of energy sales. Those values are shown at the bottom of the graph for each of the energy reduction bars. Currently, the Company is producing actual energy reductions at a rate of about .5% of system energy sales. That is compared to a projected energy reduction of about .7% of sales in 2015. The projected energy reduction for the year 2022 is around 0.8% of sales. This level of energy reductions from DSM programs falls within a range of reasonable energy reductions for utilities similarly situated to the Company. A reasonable range of energy reductions would lie in a band of .5% to 1% of sales on an incremental basis. The current level of energy reductions from the Company's DSM programs does show that the Company has some additional work to do to obtain reductions in this range, but the proposed target level for energy reductions of .5 to 1% of sales sets a realistic expectation for Company DSM objectives in the future.

The Company will continue to evaluate new measures and re-evaluate existing programs for enhancements to reach this energy reduction level within the proposed range in its next integrated resource plan. Some redesign of existing programs and proposals for new programs may be a part of the 2016 DSM submission to the Virginia SCC by September of 2016.

The Company issued an RFP for design and implementation services for future programs in December 2015**.** The RFP requested proposals for programs that may include combinations of measures from concluding programs, measures identified in the DSM Potential Study, as well as other potential cost-effective measures. Responses from the RFP will be used to evaluate the feasibility and cost-effectiveness of proposed programs for customers in the Company's service territory. Responses from this RFP were not received in time to fully assess inclusion of any future programs in this 2016 Plan.

In this 2016 Plan, there is a total reduction of 752 GWh by the end of the Planning Period. By the year 2022, there are 727 GWh of reductions included in this 2016 Plan. There are several drivers that will affect the Company's ability to meet the current level of projected GWH reductions, including the cost-effectiveness of the programs, SCC approval to implement new and continue existing programs, the final outcome of proposed environmental regulations and customers' willingness to participate in the DSM programs.

5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on the SCC and the NCUC findings and rulings in the Company's Virginia DSM proceedings (Case Nos. PUE-2009-00023, PUE-2009-00081, PUE-2010-00084, PUE-2011-00093, PUE-2012-00100, PUE-2013-00072, and PUE-2014-00071), and the North Carolina DSM proceedings (Docket No. E-22, Subs 463, 465, 466, 467, 468, 469, 495, 496, 497, 498, 499, 500, 507, 508, 509, and 523), the Company's future DSM programs are evaluated on both an individual and portfolio basis.

From the 2013 Plan and going forward, the Company made changes to its DSM screening criteria in recognition of amendments to Va. Code § 56-576 enacted by the Virginia General Assembly in 2012 that a program "shall not be rejected based solely on the results of a single test." The Company has adjusted the requirement that the Total Resources Cost ("TRC") test score be 2.0 or better when the Ratepayer Impact Measure ("RIM") test is below 1.0 and the Utility Cost and Participant tests have passing scores. The Company will now consider including DSM programs that have passing scores (cost/benefit scores above 1.0) on the Participant, Utility Cost and TRC tests.
Although the Company uses these criteria to assess DSM programs, there are circumstances that require the Company to deviate from the aforementioned criteria and evaluate certain programs that

do not meet these criteria on an individual basis. These DSM programs serve important policy and public interest goals, such as that recognized by the SCC in Case No. PUE-2009-00081 and by the NCUC in Docket No. E-22, Sub 463 in approving the Company's Low Income Program, and more recently, the Company's Income & Age Qualifying Home Improvement Program (approved by the SCC in Case No. PUE-2014-00071 and NCUC in Docket No. E-22, Sub 523).

5.5.2 REJECTED DSM PROGRAMS

The Company did not reject any programs as part of the 2016 Plan process, but continues to evaluate them. A list of DSM rejected programs from prior IRP cycles is shown in Figure 5.5.2.1. Rejected programs may be re-evaluated and included in future DSM portfolios.

Figure 5.5.2.1 - IRP Rejected DSM Programs

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Programmable Thermostat Program[1]
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program
Residential Comprehensive Energy Audit Program
Residential Radiant Barrier Program
Residential Lighting (Phase II) Program
Non-Residential Refrigeration Program
Cool Roof Program
Non-Residential Data Centers
Non-Residential Recommissioning
Non-Residential Curtailable Service
Non-Residential Custom Incentive
Enhanced Air Conditioner Direct Load Control Program
Residential Controllable Thermostat Program
Residential Retail LED Lighting Program
Residential New Homes Program
Qualifying Small Business Improvement Program[2]

Note: 1) Program previously rejected; new program design based on updated information submitted in Case No. PUE-2015-00089.
2) Modified consistent with Final Order in Case No. PUE-2014-00071 and proposed as the "Small Business Improvement Program" in Case No. PUE-2015-00089.

5.5.3 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness as currently conducted in Virginia and North Carolina.

5.5.4 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.4.1 represents approximately 752 GWh in energy savings from DSM programs at a system-level by 2031.

Figure 5.5.4.1 - DSM Energy Reductions

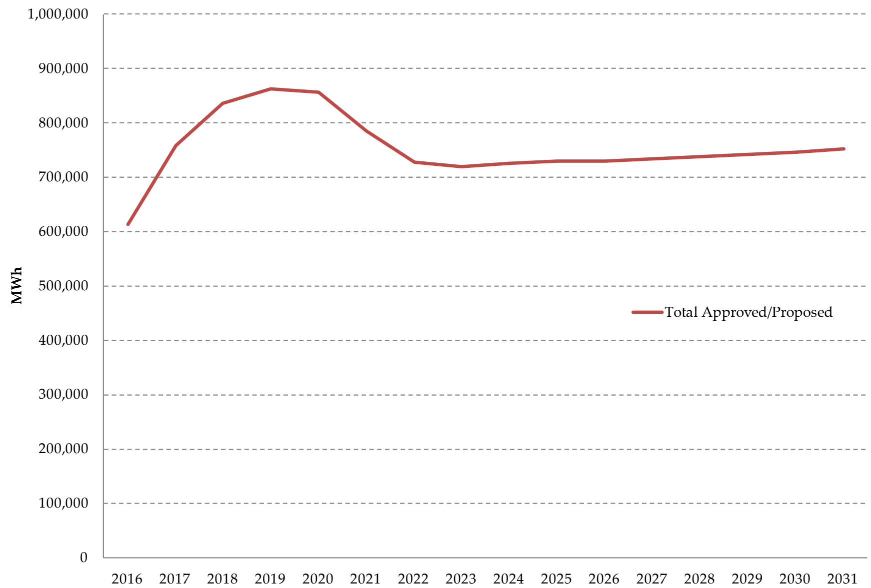
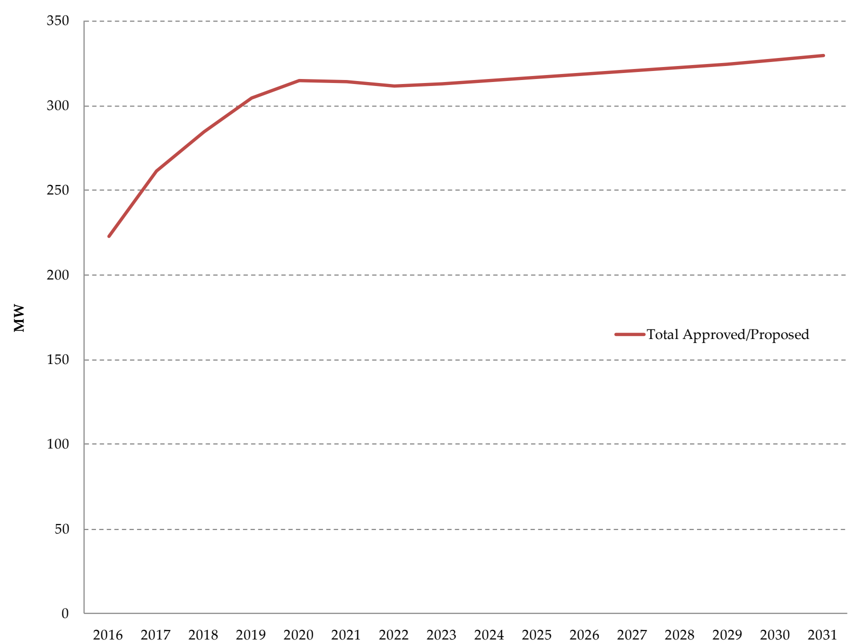


Figure 5.5.4.2 represents a system coincidental demand reduction of approximately 330 MW by 2031 from the DSM programs at a system-level.

Figure 5.5.4.2 - DSM Demand Reductions



The capacity reductions for the portfolio of DSM programs in this 2016 Plan are lower than the projections in the 2015 Plan. The total capacity reduction by the end of the Planning Period was 611 MW for the portfolio of DSM programs in the 2015 Plan and is 330 MW in this 2016 Plan. This represents approximately a 46% decrease in demand reductions. The energy reduction for the DSM programs was 3,008 GWh in the 2015 Plan and is approximately 752 GWh in this 2016 Plan. This represents a 75% decrease in energy reductions. The majority of the decrease in energy from the 2015 Plan to the 2016 Plan is attributable to the removal of the Voltage Conservation Program as a DSM initiative. The Company's decision to remove the Voltage Conservation Program as a future DSM program is discussed more in Chapter 7. In addition, certain future programs included in the 2015 Plan were not ultimately selected for the Company's proposed DSM programs in the 2015 DSM filing.

DSM Levelized Cost Comparison
As required by the SCC in its Final Order on the 2013 Plan issued on August 27, 2014 in Case No. PUE-2013-00088, the Company is providing a comparison of the cost of the Company's expected demand-side management costs per MWh relative to its expected supply-side costs per MWh. The costs are provided on a levelized cost per MWh basis for both supply-side and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirement for the selected supply-side options. The revenue requirements consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost/benefit runs for each of the demand-side options. The costs include the yearly program cash flow streams, that incorporate program costs, customer incentives and EM&V costs. The NPV of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Figure 5.5.4.3.

Figure 5.5.4.3 – Comparison of per MWh Costs of Selected Generation Resources to Phase II through Phase V Programs

Comparison of per MWh Costs of Selected Generation Resources to Phase II through Phase V Programs	Cost ($/MWh)
Non-Residential Energy Audit Program	$16.60
Non-Residential Window Film Program	$17.62
Residential Heat Pump Upgrade Program	$20.92
Non-Residential Heating and Cooling Efficiency Program	$32.90
Non-Residential Duct Sealing Program	$37.19
Non-Residential Lighting Systems and Controls Program	$44.86
Residential Duct Testing & Sealing Program	$47.73
Residential Appliance Recycling Program	$65.08
Small Business Improvement Program	$66.14
Fixed Tilt Solar 20 MW[1]	$76.15
Horizontal Tracking Solar 20 MW[1]	$77.43
Fixed Tilt Solar 80 MW[1]	$82.55
Horizontal Tracking Solar 80 MW[1]	$84.78
Generic 3X1 Dual Fuel	$95.57
Residential Programmable Thermostat EE Program	$96.36
Generic 2X1 Dual Fuel	$101.21
On Shore Wind	$104.02
Generic 1X1 Dual Fuel	$114.72
Residential Home Energy Check-up Program	$118.90
Residential Heat Pump Tune-up Program	$133.90
Brownfield CT	$140.51
North Anna 3	$151.19
Biomass	$182.72
Fuel Cell	$191.04
Income and Age Qualifying Home Improvement Program	$224.43
SCPC w/ CCS	$326.58
Off Shore Wind	$363.82
IGCC w/ CCS	$488.59
VOWTAP	$757.12

Note: The Company does not use levelized costs to screen DSM programs. Figure 5.5.4.3 only represents the cost side of DSM programs on a per MWh basis. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost/benefit tests discussed in Section 5.5.1 is the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and is the method the Company uses to screen DSM programs.

1) Values shown for these units reflect the Cost of Service method.

5.5.5 LOAD DURATION CURVES

The Company has provided load duration curves for the years 2017, 2021, and 2031 in Figures 5.5.5.1, 5.5.5.2, and 5.5.5.3.

Figure 5.5.5.1 - Load Duration Curve 2017

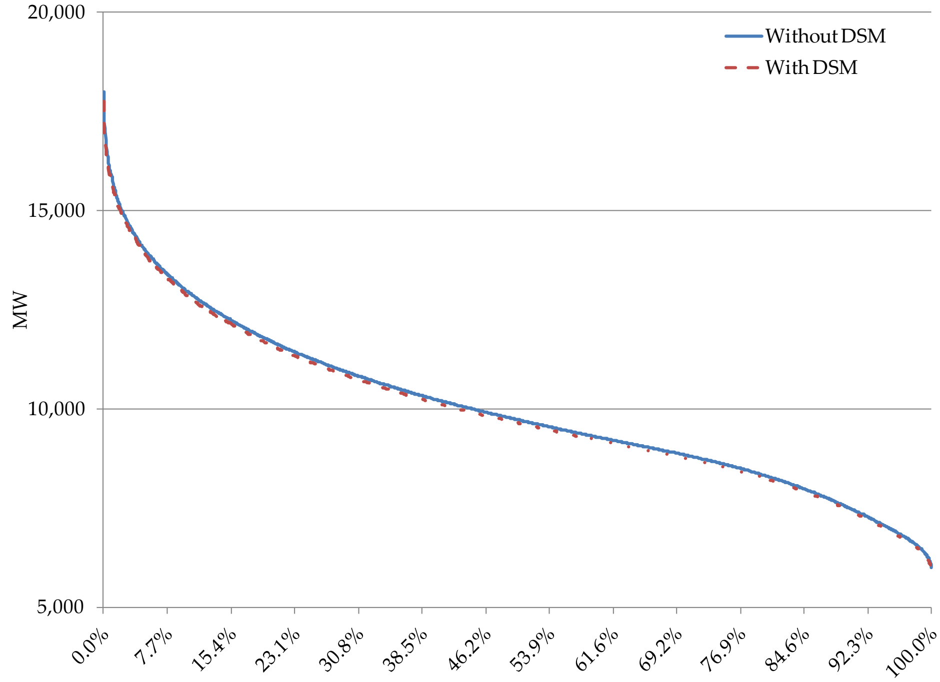
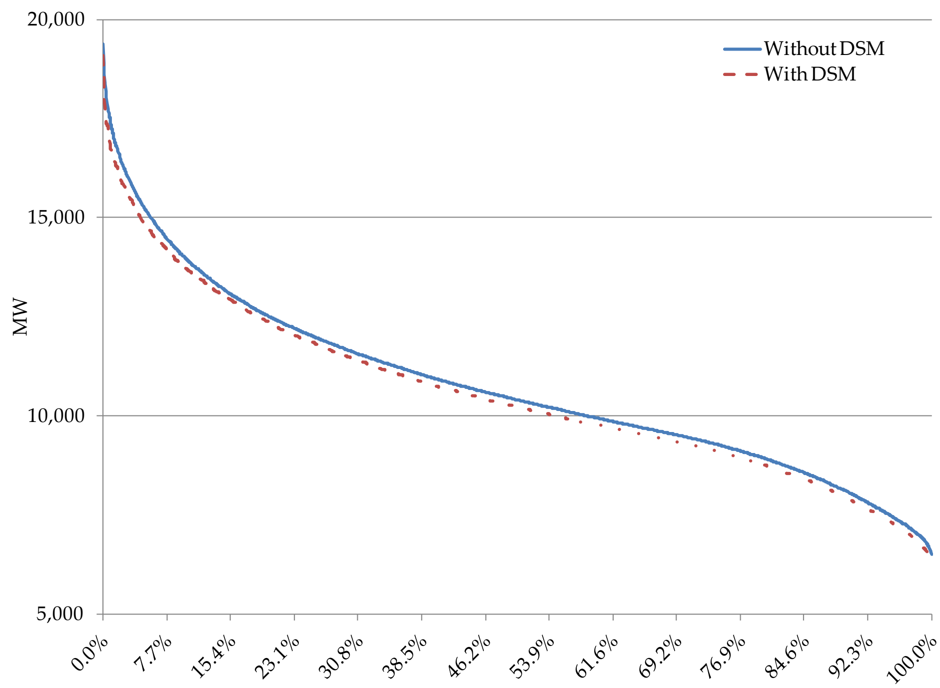
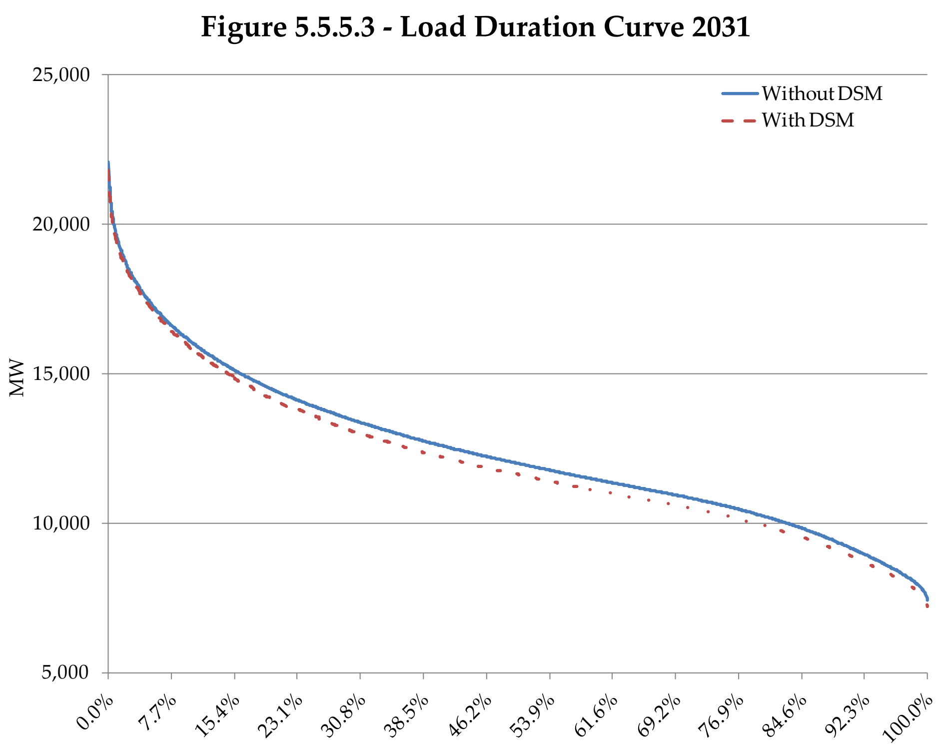


Figure 5.5.5.2 - Load Duration Curve 2021





5.6 FUTURE TRANSMISSION PROJECTS

Appendix 5F provides a list of the Company's transmission interconnection projects for the Planning Period with associated enhancement costs. Appendix 5G provides a list of transmission lines that are planned to be constructed during the Planning Period.

CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

6.1 IRP PROCESS

The IRP process identifies, evaluates, and selects a variety of new resources to augment existing resources in order to meet customers' growing capacity and energy needs. The Company's approach to the IRP process relies on integrating supply-side resources, market purchases, cost-effective DSM programs, and transmission options over the Study Period. This integration is intended to produce a long-term plan consistent with the Company's commitment to provide reliable electric service at the lowest reasonable cost and mitigate risk of unforeseen market events, while meeting all regulatory and environmental requirements. This analysis develops a forward-looking representation of the Company's system within the larger electricity market that simulates the dispatch of its electric generation units, market transactions, and DSM programs in an economic and reliable manner.

The IRP process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity needs to maintain reliable service for its customers over the Study Period.

As described in Chapter 5, a feasibility screening, followed by a busbar screening curve analysis, are then conducted, to identify supply-side resources, and a cost/benefit screening is conducted to determine demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are next incorporated into the Company's planning model, Strategist. The Strategist model then optimizes the quantity, type, and timing of these new resources based on their economics to meet the Company's future energy and capacity requirements.

The next step is to develop a set of alternative plans, which represent plausible future paths considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against plausible scenarios that may occur given future market and regulatory uncertainty. In order to test the plans, the Company creates several scenarios to measure the strength of each alternative plan as compared to other plans under a variety of conditions represented by these scenarios.

As a result of stakeholder input and consistent with the SCC's Final Order on the 2013 Plan issued in Case No. PUE-2013-00088 on August 27, 2014, the Company has included in this integrated resource plan a comprehensive risk analysis of the trade-off between operating cost risk and project development cost risk of each of the Studied Plans, and has included a broad band of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices, renewable energy credit costs, and construction costs. This analysis, which is described further in Section 6.8, attempts to quantify the fuel price, CO_2 emissions price, and construction cost risks represented in each of the Studied Plans.

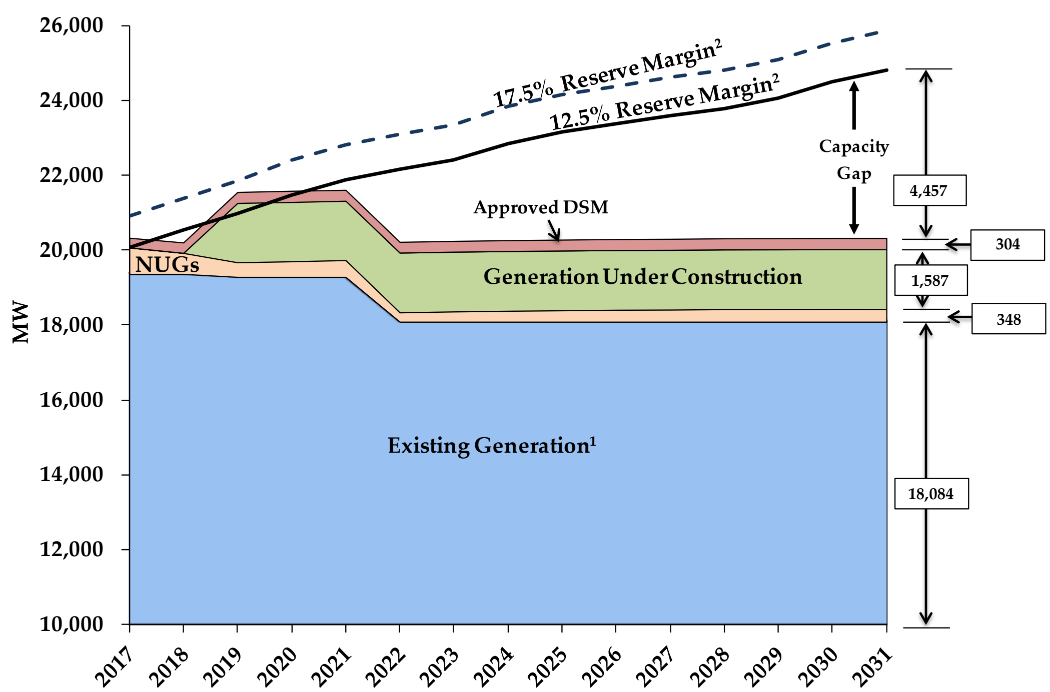
Finally, in order to summarize the results of the Company's overall analysis of the Studied Plans, the Company developed a Portfolio Evaluation Scorecard. This Scorecard matrix combines the NPV cost results and the comprehensive risk analysis results along with other assessment criteria, such as Rate Stability and Capital Investment Concentration.

The Scorecard has been applied to the Studied Plans and the results are presented and discussed in Section 6.9. The results provided by the Scorecard analysis reflect several compliant and strategic paths that the Company maintains could best meet the energy and capacity needs of its customers at the lowest reasonable cost over the Planning Period, with due quantification, consideration and analysis of future risks and uncertainties facing the industry, the Company, and its customers.

6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2, over the Planning Period, the Company forecasted average annual growth rates of 1.5% and 1.5% in peak and energy requirements, respectively, for the DOM LSE. Chapter 3 presented the Company's existing supply- and demand-side resources, NUG contracts, generation retirements, and generation resources under construction. Figure 6.2.1 shows the Company's supply- and demand-side resources compared to the capacity requirement, including peak load and reserve margin. The area marked as "capacity gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the capacity requirement. The Company plans to meet this capacity gap using a diverse combination of additional conventional and renewable generating capacity, DSM programs, and market purchases.

Figure 6.2.1 - Current Company Capacity Position (2017 – 2031)



Note: The values in the boxes represent total capacity in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

2) See Section 4.2.2.

As indicated in Figure 6.2.1, the capacity gap at the end of the Planning Period is significant. The Planning Period capacity gap is expected to be approximately 4,457 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall below the required 12.46% planning reserve margin (as shown in Figure 4.2.2.1) beginning in 2018 and continue to decrease thereafter. Figure 6.2.2 displays actual reserve margins from 2017 to 2031.

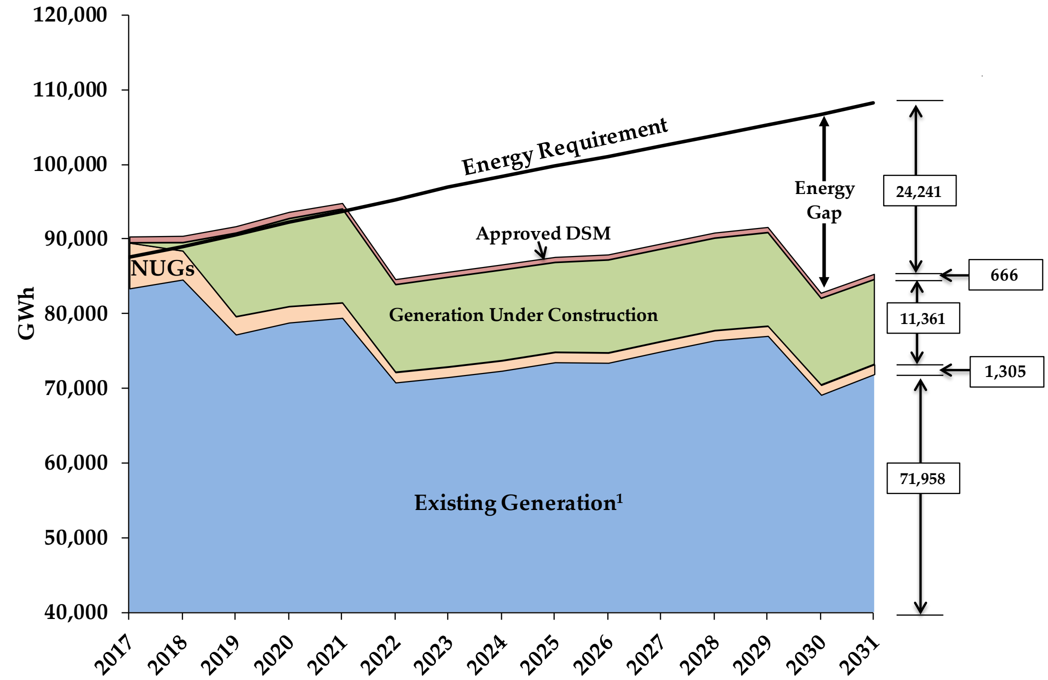
Figure 6.2.2 - Actual Reserve Margin without New Resources

Year	Reserve Margin (%)
2017	13.4%
2018	10.3%
2019	6.9%
2020	4.9%
2021	3.1%
2022	-5.4%
2023	-6.3%
2024	-8.1%
2025	-9.2%
2026	-10.0%
2027	-10.8%
2028	-11.5%
2029	-12.5%
2030	-14.0%
2031	-15.1%

The Company's PJM membership has given it access to a wide pool of generating resources for energy and capacity. However, it is critical that adequate reserves are maintained not just in PJM as a whole, but specifically in the DOM Zone to ensure that the Company's load can be served reliably and cost-effectively. Maintaining adequate reserves within the DOM Zone lowers congestion costs, ensures a higher level of reliability, and keeps capacity prices low within the region.

Figure 6.2.3 illustrates the amount of annual energy required by the Company after the dispatch of its existing resources. The figure shows that the Company's energy requirements increase significantly over time.

Figure 6.2.3 - Current Company Energy Position (2017 – 2031)



Note: The values in the boxes represent total energy in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

The Company's long-term energy and capacity requirements shown in this section are met through an optimal mix of new conventional and renewable generation, DSM, and market resources using the IRP process.

6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of the Studied Plans to evaluate the types and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions including, but not limited to, load, fuel prices, emissions costs, maintenance costs, and resource costs were used as inputs to Strategist. Concurrently, supply-side resources underwent feasibility and busbar screening analyses as discussed in Chapter 5. This analysis provided a set of future supply-side resources potentially available to the Company, along with their individual characteristics. The types of supply-side resources that are available to the Strategist model are shown in Figure 6.3.1.

Figure 6.3.1 - Supply-Side Resources Available in Strategist

Dispatchable
Biomass
CC 1x1
CC 2x1
CC 3x1
Coal w/CCS
CT
Fuel Cell
IGCC w/CCS
Nuclear (NA3)
Non-Dispatchable
Offshore Wind
Onshore Wind
Solar NUG
Solar PV
Solar Tag
VOWTAP

Key: CC: Combined-Cycle; CT: Combustion Turbine (2 units); IGCC CCS: Integrated-Gasification Combined-Cycle with Carbon Capture and Sequestration; Coal CCS: Coal with Carbon Capture and Sequestration; Solar PV: Solar Photovoltaic; Solar Tag: Solar PV unit at a brownfield site; VOWTAP: Virginia Offshore Wind Technology Advancement Project.

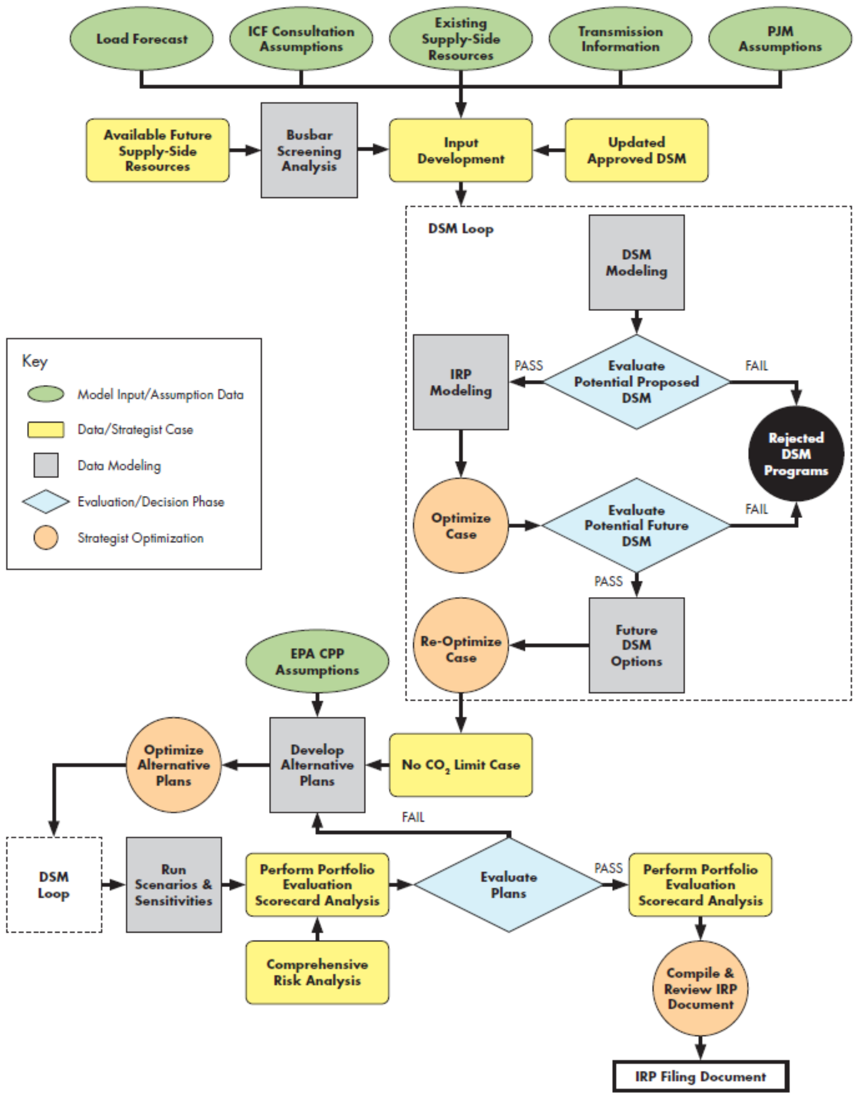
As described in Chapter 5, the Company continues to evaluate the potential for new DSM programs or modifications to existing programs for possible filing in Virginia by September 2016. This may also lead to modifications or additions to the portfolio of DSM programs in North Carolina. Supply-side options, market purchases and currently-approved demand-side resource options were optimized to arrive at the Studied Plans presented in this 2016 Plan filing. The level of DSM is the same in all of the Studied Plans.

Strategist develops resource plans based on the total NPV utility costs over the Study Period. The NPV utility costs include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs and economic carrying costs of future resources.

To create the Company's 2016 Plan, the Company developed the Studied Plans representing plausible future paths, as described in Section 6.4. The four CPP-Compliant Alternative Plans and Plan A: No CO_2 Limit (i.e., the Studied Plans) were then analyzed and tested against a set of scenarios designed to measure the relative cost performance of each plan under varying market, commodity, and regulatory conditions.

The Studied Plans were also subjected to a comprehensive risk analysis to assess portfolio risks associated with fuel costs, CO_2 emission costs, and construction costs. In general, this analysis was used to quantify the value of fuel diversity. Finally, the results of all the analyses were summarized in the Portfolio Evaluation Scorecard, where each of the Studied Plans was given a final score under various evaluation categories such as cost and risk.

Figure 6.3.2 - Plan Development Process



6.4 STUDIED PLANS

The Company's analysis of the Studied Plans is intended to represent plausible paths of future resource additions. The CPP-Compliant Alternative Plans presume the CPP will be implemented in accordance with the EPA's final CPP rule and the model trading rules as currently proposed, and are designed to ensure that the Company's Virginia-based generation fleet achieves compliance with four likely alternative programs that Virginia may choose under the CPP as described in Chapter 3. The design also anticipates that the Company's Mt. Storm facility in West Virginia operates in a manner consistent with a Mass-Based program, which the Company believes is the likely program choice for West Virginia. The Company's Rosemary Power Station in North Carolina was assumed to continue operations without additional constraints. Each of the Alternative Plans was optimized using least-cost analytical techniques given the Intensity-Based or Mass-Based constraints associated with that alternative, to meet the differing compliance approaches. Plan E: Mass-Based Emissions Cap (existing and new units) was the only alternative that economically selected a new nuclear facility (North Anna 3). Figure 6.4.1 reflects the Studied Plans in tabular format.

Figure 6.4.1 – 2016 Studied Plans

Year		Compliant with Clean Power Plan				Renewables, Retirements, Extensions and DSM included in all Plans			
	Plan A: No CO_2 Limit	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)	Renewable	Retrofit	Retire	DSM[1]
2017						SLR NUG (204 MW)[3] SPP (7 MW)[3]		YT 1-2	Approved & Proposed DSM 330 MW by 2031 752 GWh by 2031
2018						VOWTAP	PP5 - SNCR		
2019	Greensville	Greensville	Greensville	Greensville	Greensville				
2020		SLR (200 MW)	SLR (400 MW)	SLR (200 MW)	SLR (800 MW)	VA SLR (400 MW)[6]			
2021		SLR(200MW)	SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2022	CT	3x1 CC SLR (200 MW)	3x1 CC SLR (400 MW)	3x1 CC SLR (200 MW)	2x1 CC CT SLR (800 MW)			YT 3[4], CH 3-4[4], CH 5-6[4], CL 1-2[4], MB 1-2[4]	
2023	CT	CT SLR (200 MW)	SLR (400 MW)	CT SLR (200 MW)	SLR (800 MW)				
2024		SLR (200 MW)	CT SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2025		SLR (100 MW)	SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2026			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2027			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2028	3x1 CC		SLR (200 MW)	SLR (200 MW)	SLR (600 MW)				
2029			SLR (200 MW)	SLR (200 MW)	NA3[2]			VCHEC[5]	
2030		3x1 CC	SLR (200 MW)	3x1 CC SLR (200 MW)					
2031			SLR (200 MW)	SLR (200 MW)					

Key: Retire: Remove a unit from service; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; NA3: North Anna 3; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SPP: Solar Partnership Program; VA SLR: Generic Solar built in Virginia; VCHEC: Virginia City Hybrid Energy Center; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Note: Generic SLR shown in the Studied Plans is assumed to be built in Virginia.

1) DSM capacity savings continue to increase throughout the Planning Period.

2) Earliest possible in-service date for North Anna 3 is September 2028, which is reflected as a 2029 capacity resource.

3) SPP and SLR NUG started in 2014. 600 MW of North Carolina Solar NUGs include 204 MW in 2017; 396 MW was installed prior to 2017.

4) The potential retirement of Yorktown Unit 3 and the potential retirements of Chesterfield Units 3-4 and Mecklenburg Units 1-2 are modeled in all of the CPP-Compliant Alternative Plans (B, C, D and E). The potential retirements of Chesterfield Units 5-6 and Clover Units 1-2 are modeled in Plan E. The potential retirements occur in December 2021, with capacity being unavailable starting in 2022.

5) The potential retirement of VCHEC in December 2028 (capacity unavailable starting in 2029) is also modeled in Plan E.

6) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 to 2020.

Along with the individual characteristics of the CPP-Compliant Alternative Plans, the Studied Plans share a number of generation resource assumptions, including, but not limited to, the resources for which the Company has filed and/or has been granted CPCN approval from the SCC, or has publicly committed to pursuing, subject to SCC approval. These resources include Greensville County Power Station, 400 MW of Virginia utility-scale solar generation (including Scott, Whitehouse and Woodland, totaling 56 MW), VOWTAP (12 MW), and the SPP (7 MW). In addition, all of the Studied Plans assume a 20-year license extension of the Company's existing nuclear fleet at Surry and North Anna.

The Studied Plans have the same level of approved and proposed DSM programs reaching 330 MW by the end of the Planning Period. Additionally, the Studied Plans include North Carolina solar NUGs (600 MW) by 2017, and the retirement of Yorktown Units 1 (159 MW) and 2 (164 MW) by 2017.

The CPP-Compliant Alternative Plans (B, C, D and E) were designed using ICF's CPP commodity forecast. In addition to the supply- and demand-side resources listed above that are common to all of the Studied Plans, the four CPP-Compliant Alternative Plans also model the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Yorktown Unit 3 (790 MW) all in 2022. Additional resources and retirements are included in the Studied Plans below:

Plan A: No CO_2 Limit

Plan A is based on the No CO_2 Cost scenario and is developed using least cost modeling methodology. Specifically, it selects:

- 1,591 MW of 3x1 CC capacity (one CC); and
- 915 MW of CT (two CTs) capacity.

CPP-Compliant Alternative Plans

Plan B: Intensity-Based Dual Rate

Plan B represents an Intensity-Based CO_2 program that requires each existing: (a) fossil-fueled steam unit to achieve an intensity target of 1,305 lbs of CO_2 per MWh by 2030, and beyond; and (b) NGCC units to achieve an intensity target of 771 lbs of CO_2 per MWh by 2030, and beyond. Plan B selects:

- 1,100 MW (nameplate) of solar;
- 3,183 MW of 3x1 CC capacity (two CCs); and
- 458 MW of CT (one CT) capacity.

Plan C: Intensity-Based State Average
Plan C is an Intensity-Based CO_2 program that requires all existing fossil fuel-fired generation units to achieve a portfolio average intensity target by 2030, and beyond. In Virginia, that average intensity is 934 lbs of CO_2 per MWh by 2030, and beyond. Plan C selects:

- 3,400 MW (nameplate) of solar;
- 1,591 MW of 3x1 CC capacity (one CC); and
- 458 MW of CT (one CT) capacity.

Plan D: Mass-Based Emissions Cap (existing units only)
Plan D is a Mass-Based program that limits the total CO_2 emissions from the existing fleet of fossil fuel-fired generating units. In Virginia, this limit is 27,433,111 short tons of CO_2 in 2030, and beyond. Specifically, Plan D selects:

- 2,400 MW of solar;
- 3,183 MW of 3x1 CC capacity (two CCs); and
- 458 MW of CT (one CT) capacity.

Plan E: Mass-Based Emissions Cap (existing and new units)
Plan E is a Mass-Based program that limits the total CO_2 emissions from both the existing fleet of fossil fuel-fired generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of CO_2 in 2030, and beyond. Specifically, Plan E selects:

- 7,000 MW of solar;
- 1,452 MW of nuclear (North Anna 3);
- 1,062 MW of 2x1 CC capacity (one CC);
- 1,373 MW of CT (three CTs) capacity; and
- Potential retirement of Chesterfield Units 5 and 6, Clover Units 1 and 2, and VCHEC.

Figure 6.4.2 illustrates the renewable resources included in the Studied Plans over the Study Period (2017 - 2041).

Figure 6.4.2 – Renewable Resources in the Studied Plans

Resource	Nameplate MW	Plan A: No CO_2 Limit	Compliant with the Clean Power Plan			
			Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
Existing Resources	590	x	x	x	x	x
Additional VCHEC Biomass	27	x	x	x	x	x
Solar Partnership Program	7	x	x	x	x	x
Solar NUGs	600	x	x	x	x	x
VA Solar[1]	400	x	x	x	x	x
Solar PV	Varies	-	1,100 MW	3,600 MW	2,600 MW	7,000 MW
VOWTAP	12	x	x	x	x	x

Note: 1) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).

6.5 STUDIED PLANS SCENARIOS

The Company used a number of scenarios based upon its planning assumptions to evaluate the Studied Plans. The Company's operational environment is highly dynamic and can be significantly impacted by variations in commodity prices, construction costs, environmental, and regulatory requirements. Testing multiple expansion plans under different assumptions assesses each plan's cost performance under a variety of possible future outcomes.

6.6 STUDIED PLANS NPV COMPARISON

The Company evaluated the Studied Plans using the basecase and three scenarios to compare and contrast the plans using the NPV utility costs over the Study Period. Figure 6.6.1 presents the results of the Studied Plans compared on an individual scenario basis. The results are displayed as a percentage change in costs compared to the basecase (marked with a star).

Figure 6.6.1 – 2016 Studied Plans NPV Comparison

		Plan A: No CO_2 Limit	Subject to the EPA's Clean Power Plan			
			Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
	Basecase	★	10.7%	12.4%	11.6%	26.6%
Scenarios	High Fuel	12.6%	19.3%	20.8%	20.2%	34.5%
	Low Fuel	-6.1%	-1.0%	0.7%	-0.1%	15.7%
	ICF Reference	5.4%	11.9%	13.9%	13.1%	28.8%

Note: The results are displayed as a percentage of costs compared to Plan A: No CO_2 Limit with No CO_2 Cost case assumptions (marked with star).

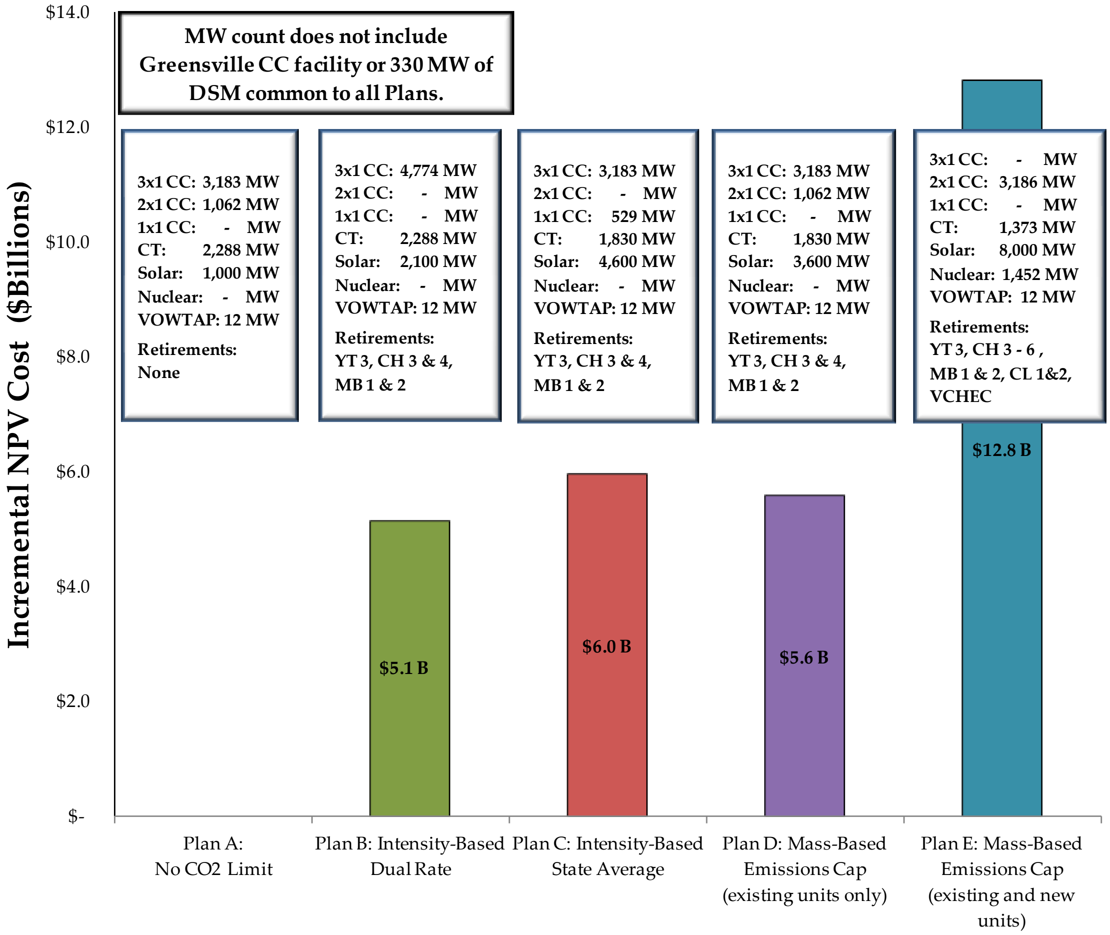
Figure 6.6.2 illustrates the NPV CPP compliance cost for the Alternative Plans by showing the additional expenditures required by the CPP-Compliant Alternative Plans over Plan A: No CO_2 Limit for the Study Period.

Figure 6.6.2 – NPV CPP Compliance Cost of the Alternative Plans over Plan A: No CO_2 Limit

	Subject to the EPA's Clean Power Plan			
	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
NPV CPP Compliance Cost	$5.14B	$5.95B	$5.57B	$12.81B

Figure 6.6.3 illustrates the incremental NPV CPP compliance cost for the Alternative Plans over Plan A: No CO_2 Limit for the Study Period.

Figure 6.6.3 – Incremental NPV CPP Compliance Cost of the Alternative Plans over Plan A: No CO_2 Limit (2017 – 2041)



Pursuant to its Final Order on the 2015 Plan (PUE-2015-00035), the SCC directed the Company to perform an optimum timing analysis that assessed the cost of delaying the in-service date of North Anna 3. Using least-cost planning techniques and due to the high initial cost of North Anna 3 coupled with a relative low price forecast for natural gas, the optimal timing of the North Anna 3 facility is beyond the term of the Study Period for all Studied Plans except for Plan E: Mass-Based Emissions Cap (existing and new units). In Plan E, the optimal timing for North Anna 3 is 2029.

Delaying North Anna 3 beyond this time period would require additional solar PV built beyond the approximately 7,000 MW already included in Plan E, in order to comply with a Mass-Based program for existing and new units. Given the current land requirements for solar PV (8 acres per MW), 7,000 MW or more of solar PV is simply not practical at this point in time. Therefore, the Company maintains that the timing of North Anna 3 in Plan E is optimal.

6.7 RATE IMPACT ANALYSIS

6.7.1 OVERVIEW

In its Final Order on the 2015 Plan (Case No. PUE-2015-00035), the SCC directed the Company to provide a calculation of the impact of each CPP program and the FIP on the electricity rates paid by the Company's customers. Although the FIP is not yet finalized, the EPA proposed model rule for Mass-Based programs regulating existing units only is the Company's best estimate as to how the EPA would impose a Federal Plan on a state. This structure is assessed in Plan D: Mass-Based Emissions Cap (existing units only) and included in this 2016 Plan.

6.7.2 ALTERNATIVE PLANS COMPARED TO PLAN A: NO CO_2 LIMIT

The Company evaluated the residential rate impact of each CPP-Compliant Alternative Plan against Plan A: No CO_2 Limit. The results of this analysis are shown in Figure 6.7.2.1 and reflect both the dollar impact and percentage increase for a typical residential customer, using 1,000 kWh per month, each year starting in 2017 through 2041.

Figure 6.7.2.1 – Monthly Rate Increase of Alternative Plans vs. Plan A: No CO_2 Limit

	Increase Compared to Plan A: No CO_2 Limit ($)				Increase Compared to Plan A: No CO_2 Limit (%)			
	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
2017	0.41	0.41	0.25	0.65	0.4%	0.4%	0.2%	0.6%
2018	0.71	0.71	0.54	0.87	0.6%	0.6%	0.5%	0.8%
2019	1.43	1.43	1.32	1.64	1.3%	1.3%	1.1%	1.4%
2020	3.38	4.29	2.68	8.09	2.9%	3.7%	2.3%	7.0%
2021	3.68	4.53	3.24	11.28	3.1%	3.9%	2.8%	9.6%
2022	7.11	7.80	6.63	31.75	5.9%	6.5%	5.5%	26.5%
2023	4.90	5.79	4.37	21.24	4.0%	4.8%	3.6%	17.5%
2024	4.49	5.38	3.91	24.30	3.7%	4.4%	3.2%	19.9%
2025	3.21	3.48	3.10	26.24	2.6%	2.8%	2.5%	21.1%
2026	1.83	2.18	2.17	26.76	1.4%	1.7%	1.7%	21.1%
2027	2.39	1.99	2.73	27.43	1.9%	1.6%	2.1%	21.4%
2028	5.29	4.04	5.49	28.15	4.2%	3.2%	4.3%	22.2%
2029	5.63	4.15	5.70	43.31	4.4%	3.2%	4.4%	33.7%
2030	2.18	4.22	2.59	24.01	1.7%	3.2%	2.0%	18.3%
2031	1.87	4.91	2.06	21.97	1.4%	3.7%	1.5%	16.4%
2032	2.79	5.83	2.30	22.02	2.1%	4.3%	1.7%	16.2%
2033	6.13	4.88	5.58	24.31	4.5%	3.6%	4.1%	17.7%
2034	7.15	5.47	6.77	23.90	5.1%	3.9%	4.9%	17.2%
2035	5.60	6.70	6.73	24.05	4.0%	4.8%	4.8%	17.1%
2036	6.63	8.12	7.79	24.49	4.7%	5.7%	5.5%	17.2%
2037	7.44	9.44	8.63	24.07	5.1%	6.5%	6.0%	16.7%
2038	7.98	10.33	9.35	23.39	5.4%	7.0%	6.4%	15.9%
2039	8.69	10.66	10.13	22.73	5.9%	7.2%	6.8%	15.3%
2040	9.88	11.54	10.94	21.75	6.6%	7.7%	7.3%	14.5%
2041	10.28	12.36	11.64	21.71	6.7%	8.1%	7.6%	14.2%

Figure 6.7.2.2 – Residential Monthly Bill Increase for Intensity-Based Plans as Compared to Plan A: No CO_2 Limit (%)

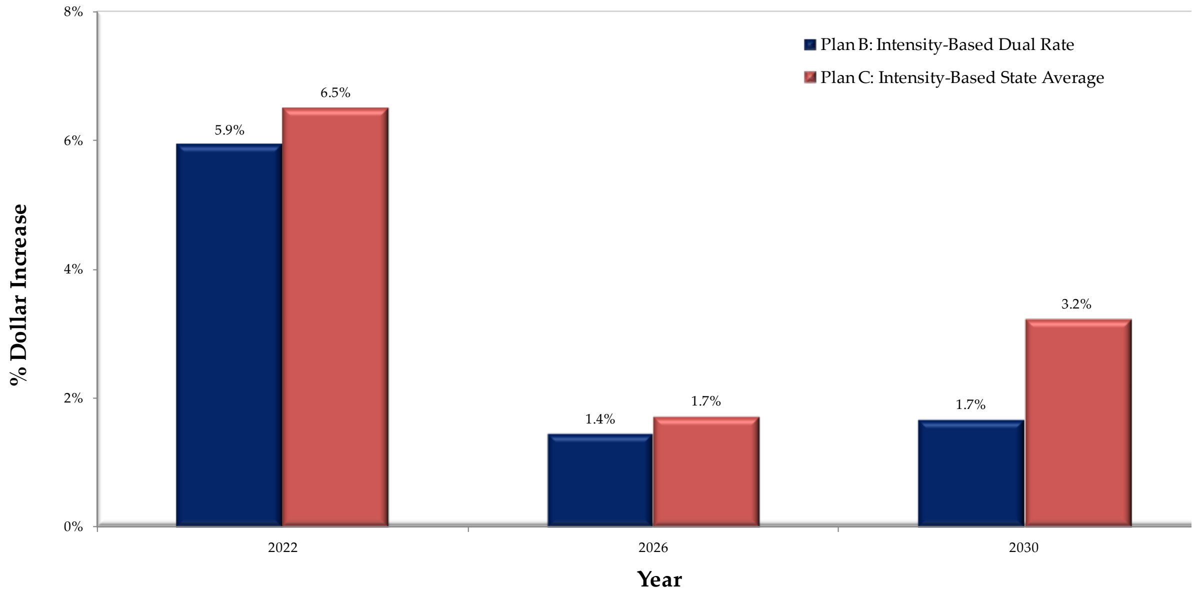


Figure 6.7.2.3 – Residential Monthly Bill Increase for Intensity-Based Plans as Compared to Plan A: No CO_2 Limit ($)

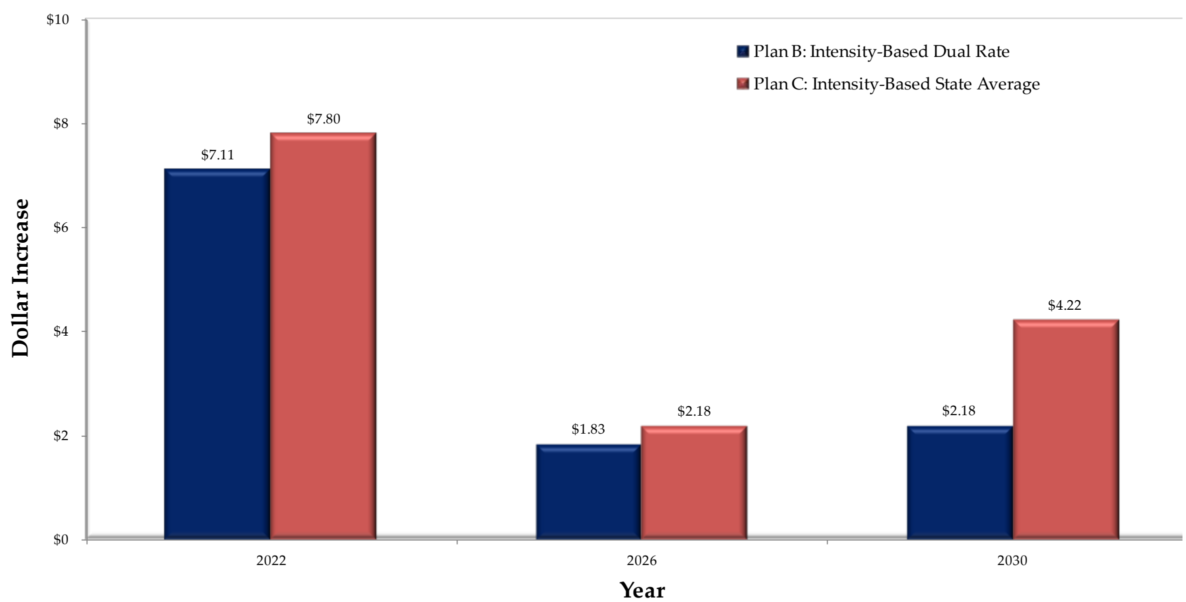


Figure 6.7.2.4 – Residential Monthly Bill Increase for Mass-Based Plans as Compared to Plan A: No CO_2 Limit (%)

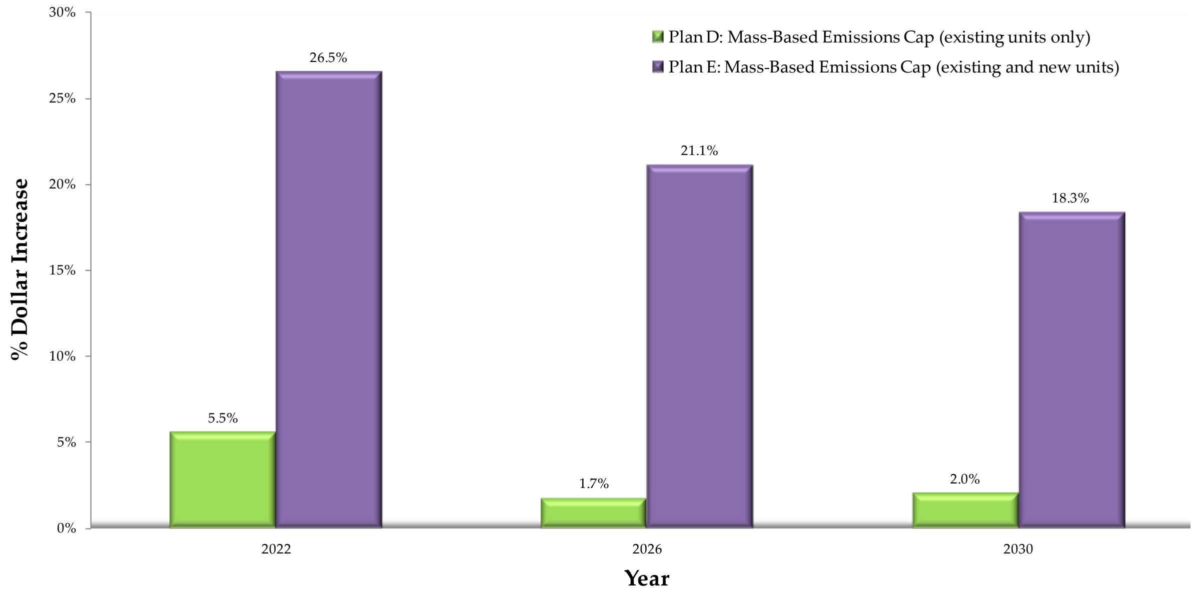


Figure 6.7.2.5 – Residential Monthly Bill Increase for Mass-Based Plans as Compared to Plan A: No CO_2 Limit ($)

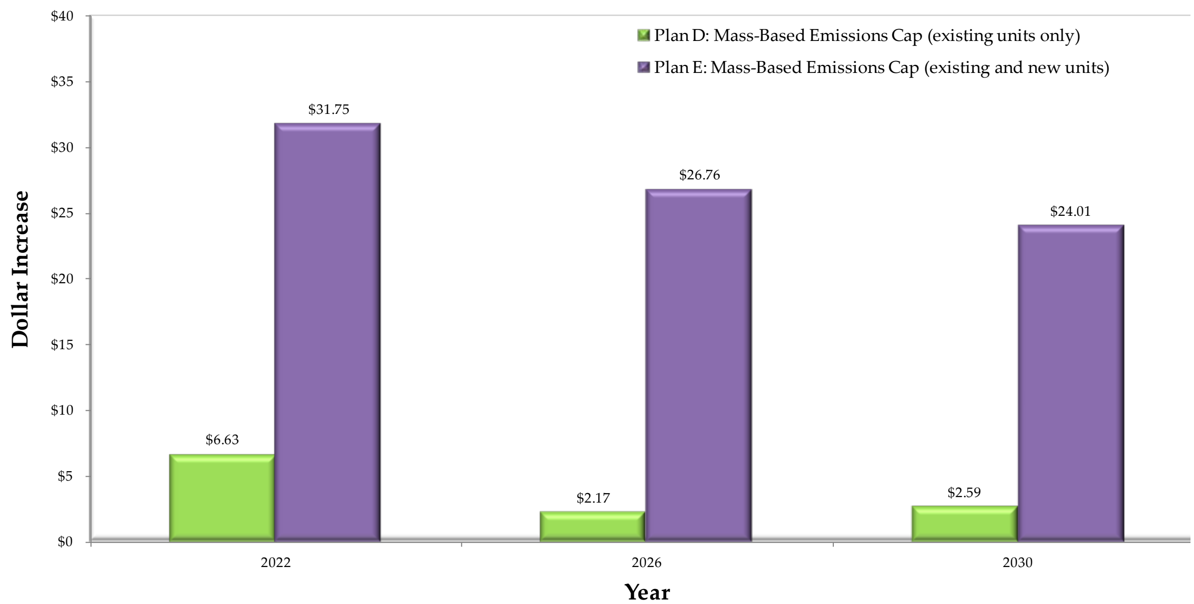


Figure 6.7.2.6 – Residential Monthly Bill Increase for Alternative Plans as Compared to Plan A: No CO_2 Limit (%)

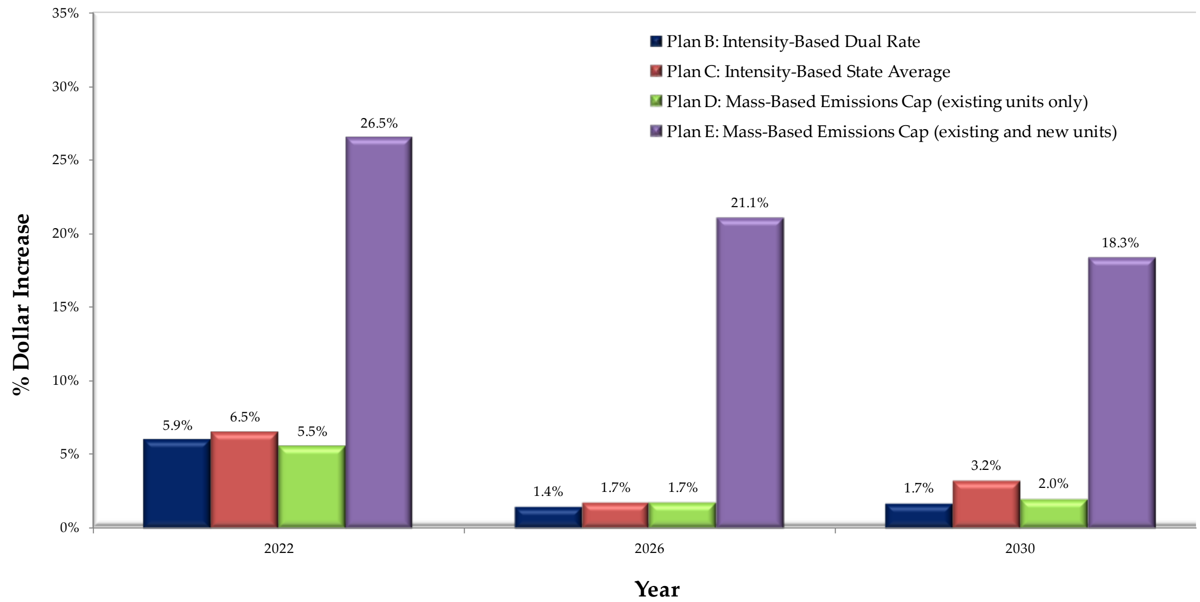


Figure 6.7.2.7 – Residential Monthly Bill Increase for Alternative Plans as Compared to Plan A: No CO_2 Limit ($)

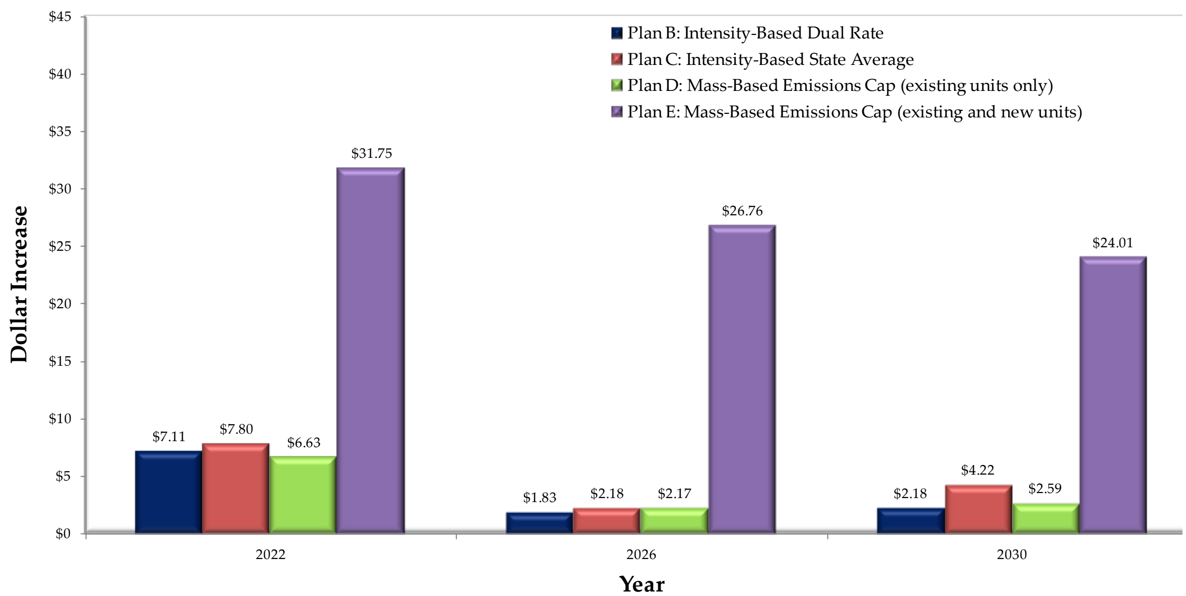


Figure 6.7.2.8 – Residential Monthly Bill Increase for CPP-Compliant Alternative Plans as Compared to Plan A: No CO_2 Limit (%)

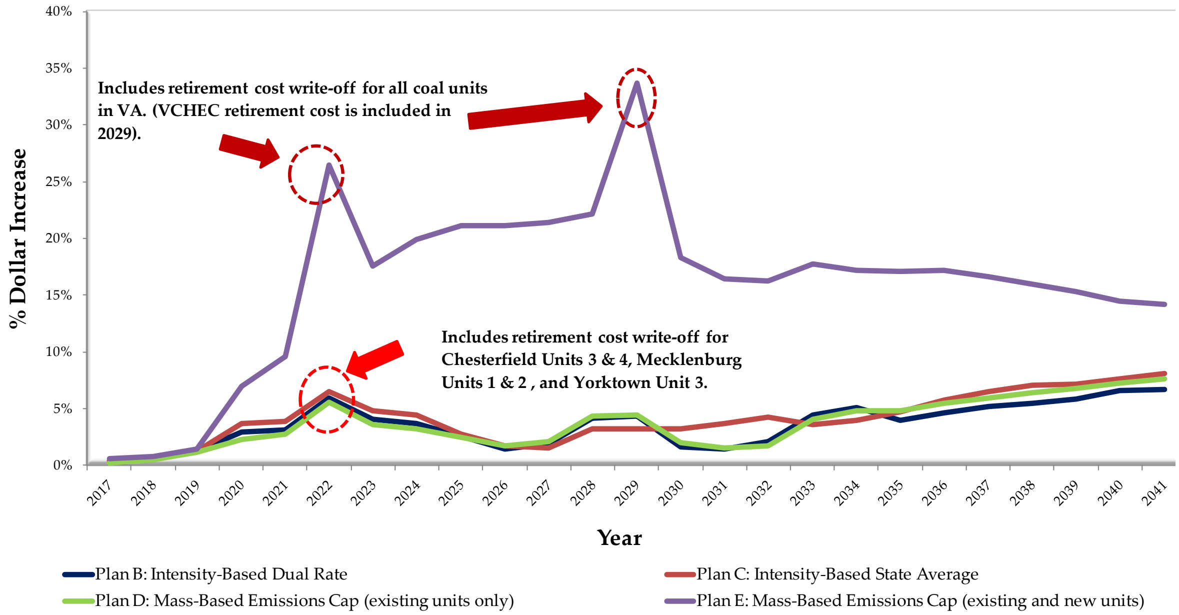
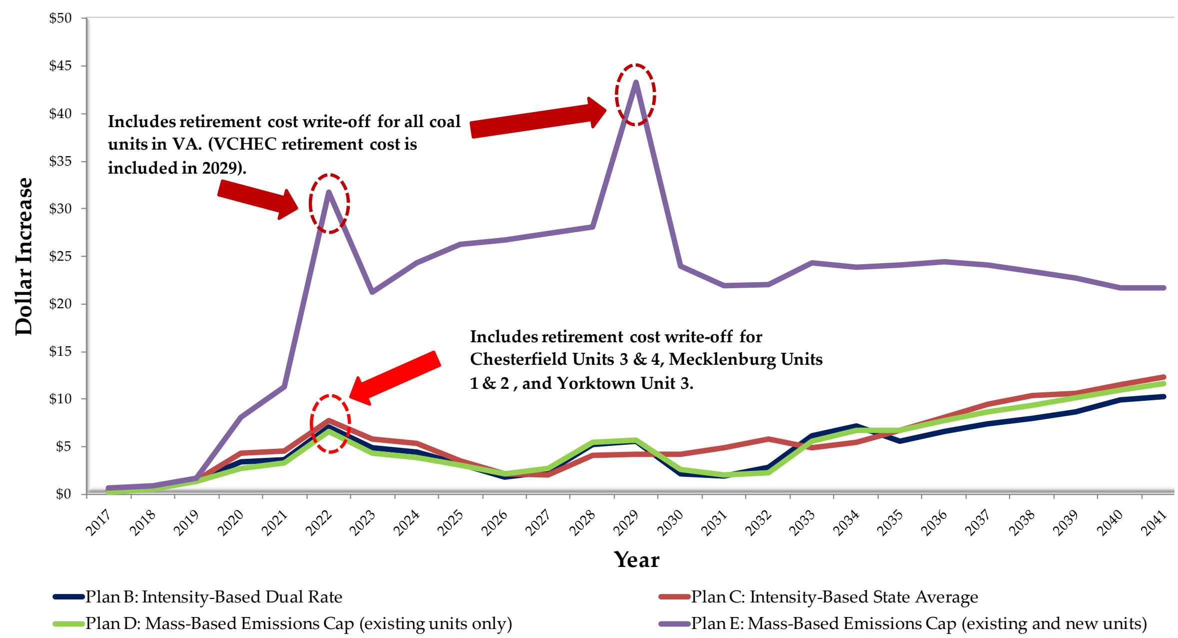


Figure 6.7.2.9 – Residential Monthly Bill Increase for CPP-Compliant Alternative Plans as Compared to Plan A: No CO_2 Limit ($)



6.8 COMPREHENSIVE RISK ANALYSIS

6.8.1 OVERVIEW

Pursuant to the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035) which directs the Company to "…continue to evaluate the risks associated with the plans that the Company prepares…" the Company is, in this 2016 Plan, including a Comprehensive Risk Analysis methodology that was applied to the Studied Plans presented in Section 6.4. The Company utilized the same stochastic (probabilistic) methodology and supporting software developed by Pace Global (a Siemens business) for use in the 2015 Plan, but with modifications to the Aurora multi-area production costing model (licensed from EPIS, Inc.) needed to reflect the EPA's final CPP regulations. Using this analytic and modeling framework (hereinafter referred to as the "Pace Global methodology"), the Studied Plans, each treated as a fixed portfolio of existing and expansion resources plus demand-side measures, were evaluated and compared on the dimensions of average total production cost relative to two measures of cost-related risk, which are standard deviation cost and semi-standard deviation cost (further explained in Section 6.8.2).

The Pace Global methodology is an adaptation of Modern Portfolio Theory, which attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk that is not addressed in the traditional least-cost planning paradigm. Measuring the risk associated with proposed expansion plans quantifies, for example, whether adopting any one particular plan comes with greater cost and cost risk for customers when compared to the cost and risk for competing plans. In the same way, comparing plans with different capacity mixes, and consequently with different cost and risk profiles, potentially reveals the value of generation mix diversity. It is important to note that it is impractical to include all possible sources of risk in this assessment but only the most significant drivers to plan cost and plan cost variability.

At a high level, the Pace Global methodology is comprised of the following steps:

- Identify and create a stochastic model for each key source of portfolio risk which in this analysis were identified:
    - Natural gas prices;
    - Natural gas basis;
    - Coal prices;
    - Load (electricity demand);
    - CO_2 emission allowance prices; and
    - New generation capital cost.
- Generate a set of stochastic realizations for the key risk factors within the PJM region and over the Study Period using Monte-Carlo techniques. For purposes of this analysis, 200 stochastic realizations were produced for each of the key risk factors;
- Subject each of the Studied Plans separately to this same set of stochastic risk factor outcomes by performing 200 Aurora multi-area model production cost simulations, which cover a significant part of the Eastern Interconnection, using the risk factor outcomes as inputs;

- Calculate from the Aurora simulation results the expected levelized all-in average cost and the associated risk measures for each of the Studied Plans.

Clean Power Plan Risk Modeling Assumptions

Each of the CPP-Compliant Alternative Plans was developed as the lowest cost means to comply with one of four corresponding CPP compliance options for the state of Virginia. In order to appropriately reflect the key features of the CPP in the risk simulations, the following general assumptions were implemented:

- With the exception of Virginia, the CPP compliance standards for each state within the simulation footprint, which included states within PJM and a significant portion of the U.S. Eastern Interconnection, were modeled according to the individual state compliance assumptions provided by ICF as shown in Appendix 4A;
- The CPP compliance standard assumed for Virginia was modeled according to that predicated for each particular Studied Plan being evaluated. In the case of Plan A: No CO_2 Limit, which was developed assuming the CPP was not in effect, the alternative was simulated under the assumption that Virginia adopts an Intensity-Based Dual Rate Program for CPP compliance for comparative purposes only;
- Stochastic draws for carbon allowance prices were based on the annual expected, high, and low prices in ICF's CPP Commodity Forecast (see Appendix 4A) and were applied to affected EGUs in any state, including Virginia under Plans D and E, assumed to adopt a Mass-Based compliance limit;
- For those states assumed to adopt an Intensity-Based compliance limit, including Virginia under Plan A, B, and C, the value of ERCs is assumed to be zero for trading purposes based on ICF's projection that abundant supply together with banking will result in no binding constraints on compliance under the Intensity-Based option.

It is important to point out that, in contrast to the risk analysis performed for the 2015 Plan, the cost and risk levels estimated for each of the Studied Plans reflect not only the inherent characteristics of each plan but also the effect of the particular Virginia CPP compliance option.

6.8.2 PORTFOLIO RISK ASSESSMENT

Upon completion of the Aurora simulations described above, post-processing of each Studied Plan's annual average total (fixed plus variable) production costs proceeded in the following steps for each Plan:

- For each of the 200 draws, the annual average total production costs are levelized over the 26 year Study Period (2017 - 2041) using a <u>real</u> discount rate of 4.24%.
- The 200 levelized average total production costs values are then statistically summarized into:
    - **Expected value**: the arithmetic average value of the 200 draws.

- **Standard deviation**: the square-root of the average of the squared differences between each draw's levelized value and the mean of all 200 levelized values. This is a standard measure of overall cost risk to the Company's customers.
- **One way (upward) standard deviation (semi-standard deviation)**: the standard deviation of only those levelized average production costs which exceed the expected value (i.e., the mean of all 200 levelized values). This is a measure of adverse cost risk to the Company's customers.

The resulting values are shown for each Studied Plan in Figure 6.8.2.1 for comparative purposes. Plans with lower values for expected levelized average cost, standard deviation, and semi-standard deviation are more beneficial for customers.

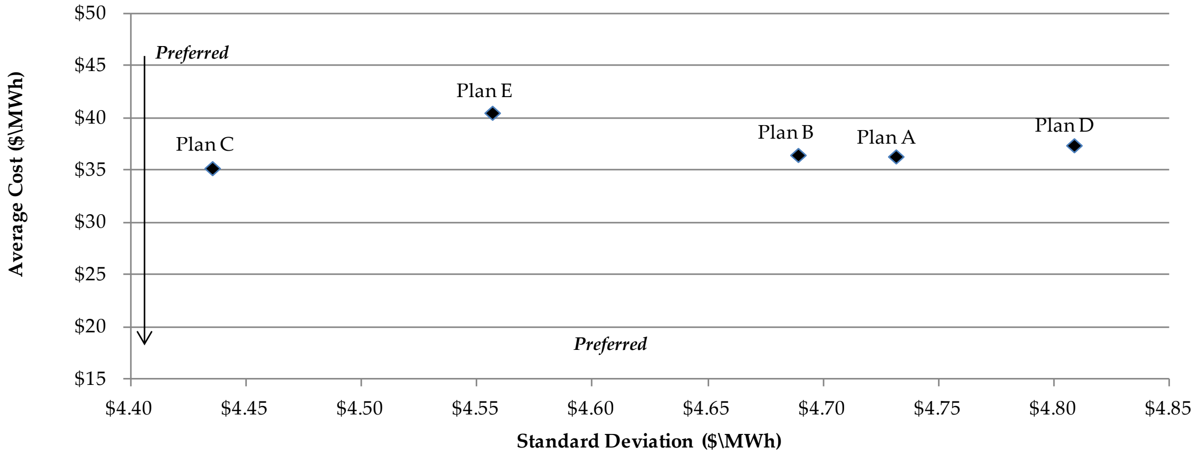
Figure 6.8.2.1 – Studied Plan Portfolio Risk Assessment Results

2016 $/MWh	Expected	Risk Measures	
Plan	Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan A: No CO_2 Limit	$36.35	$4.73	$5.05
Plan B: Intensity-Based Dual Rate	$36.49	$4.69	$4.98
Plan C: Intensity-Based State Average	$35.23	$4.44	$4.70
Plan D: Mass-Based Emissions Cap (existing units only)	$37.41	$4.81	$5.01
Plan E: Mass-Based Emissions Cap (existing and new units)	$40.53	$4.56	$4.82

It is evident that among the five Studied Plans, Plan B: Intensity-Based Dual Rate and Plan C: Intensity-Based State Average have the lowest expected cost and lowest risk (based on the standard deviation) among all CPP-Compliant Alternative Plans. Notably, both Plans B and C were developed under the Intensity-Based CPP compliance limit for Virginia. In contrast, plans developed under Mass-Based compliance for Virginia have the highest expected cost of all Studied Plans, though Plan E: Mass-Based Emissions Cap (existing and new units) has the second lowest level of risk measured by standard deviation.

The results for Plan A: No CO_2 Limit was based on simulations assuming Intensity-Based Dual Rate Program CPP compliance for Virginia. Because all simulations under Intensity-Based compliance assumed no explicit cost to emit carbon for Virginia EGUs, Plans A, B, and C can be directly compared to each other on the basis of their expansion and retirement assumptions. This comparison reveals the greater value of fuel diversity for Plan C in achieving the lowest average cost as well as the lowest risk among these plans. A visual display of the results for the Studied Plans is shown in Figure 6.8.2.2.

Figure 6.8.2.2 – Studied Plans Mean-Variance Plot



6.8.3 INCLUSION OF THE DISCOUNT RATE AS A CRITERION IN RISK ANALYSIS

In the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035) the Company was directed to "…include discount rate as a criterion in the Company's risk analysis…" As described in Section 6.4, each of the Studied Plans was developed based on minimization of total NPV utility costs over the Study Period subject to constraints, such as the reserve margin target, and CPP Intensity- or Mass-Based limits. The discount rate is a key parameter in the NPV calculation and plays an important role in computing the risk analysis results. To form a background for the subsequent discussion, the following points should be noted:

1) The appropriate discount rate to evaluate alternative expansion plans is, in principle, from the standpoint of utility customers collectively, not the utility. While the customer discount rate is unobservable, it is a function of the opportunity costs facing utility consumers. This rate would be the same regardless of the expansion plan being evaluated. Absent knowledge of the customer discount rate, it is not unreasonable to use the utility discount rate as a proxy.
2) In developing the Studied Plans and in the Comprehensive Risk Analysis, the discount rate used is the Company's five-year forecasted nominal after-tax weighted average cost of capital ("WACC"). This same discount rate is applied regardless of the expansion options under consideration. In this way, NPV costs are calculated on a consistent basis across all the Studied Plans. Since risk simulation results are in real 2016 dollars, inflation adjusted (i.e., real) after-tax WACC is used to levelize the average production costs over the Study Period for each of 200 stochastic realizations.
3) Capital revenue requirements projected for each generation expansion option are engineering, procurement, and construction ("EPC") costs only and do not include capitalized financing costs and equity return incurred prior to commercial operation.
4) The Comprehensive Risk Analysis results include the effect of uncertainty in the overnight capital cost for each type of expansion option. The risk analysis assumed greatest uncertainty for new nuclear and offshore wind projects and least for technologies for which there is

lower per project capital requirements and/or for which the Company has proven construction experience.

Inclusion of the discount rate as a risk criterion is advisable because expansion plans that include significantly large and risky future capital outlays imply that investors would require higher returns in compensation for the larger amount of capital at risk. It would also imply potentially significant changes in the Company's future capital structure such that for such plans the appropriate discount rate would be higher than that for plans comprised of less capital intensive or risky projects. In light of point #4 above, using a higher discount rate for such plans would have the incorrect and implausible result of yielding lower expected NPV costs.

An alternative approach is to apply a risk-adjusted discount rate to the plan that includes the high capital cost or high risk project. While determining the appropriate risk-adjustment to the discount rate is problematic, for the present purpose of including the discount rate as a criterion in the risk analysis, Figure 6.8.3.1 shows the results before and after a zero discount rate is applied to Plan E: Mass-Based Emissions Cap (existing and new units), which includes the highest NPV cost of the Studied Plans. Using a zero discount rate attributes the maximum possible degree of risk adjustment to the discount rate for this plan.

Figure 6.8.3.1 – Plan E: Mass-Based Emissions Cap (existing and new units)

Risk Assessment Results

2016 $/MWh Plan	Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan E: Mass-Based Emissions Cap (existing and new units) - not risk adjusted	$40.53	$4.56	$4.82
Plan E: Mass-Based Emissions Cap (existing and new units) - risk adjusted	$44.70	$5.34	$5.72

It is evident that on a risk-adjusted basis, Plan E: Mass-Based Emissions Cap (existing and new units) still has the largest expected average production cost but now also has the largest risk measured by both standard deviation and semi-standard deviation among all Studied Plans.

6.8.4 IDENTIFICATION OF LEVELS OF NATURAL GAS GENERATION WITH EXCESSIVE COST RISKS

In the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035) the Company was directed to "…specifically identify the levels of natural gas-fired generation where operating cost risks may become excessive or provide a detailed explanation as to why such a calculation cannot be made…" In this 2016 Plan, the Company is presenting five Studied Plans, each of which, with the exception of Plan A: No CO_2 Limit, was developed to comply on a standalone basis with one of four possible alternatives for Virginia under the EPA's CPP. The results of the Comprehensive Risk Analysis reflect the expected cost and estimated risk associated with each plan in the context of a particular mode of CPP compliance for Virginia. In developing each of the Studied Plans the criterion used was minimization (subject to constraints) of NPV costs without considering the associated level of risk. Studied Plan risk levels were assessed only after it was determined to be the lowest cost from among all feasible candidate plans. To have developed the Studied Plans considering both cost and risk jointly as a criterion would have required the following:

- The expansion planning process would have to determine the "efficient frontier" from among all feasible candidate plans. The efficient frontier identifies a range of feasible plans each with the lowest level of risk for its given level of expected cost. Identifying the efficient frontier is not practical using traditional utility planning software and computing resources. If the efficient frontier could be determined, then any candidate plan with risk levels higher than the efficient frontier could reasonably be characterized as having excess risk in the sense that there exists a plan on the efficient frontier with the same expected cost but with lower risk.
- The Company would need to know the "mean-variance utility function" (i.e., the risk aversion coefficient) of our customers collectively in order to select the feasible plan that optimally trades off cost and risk from among competing plans. This function could be applied regardless of whether it is possible to determine the efficient frontier. However, this function is not known and planners are thus unable to determine levels of plan risk that are unacceptable or become excessive for customers.

In the absence of these risk evaluation tools it is technically not possible to determine an absolute level of plan risk that becomes excessive, much less to determine that level of gas-fired generation within a plan that poses excessive cost risk for customers. Moreover, the absolute level of natural gas generation within a plan does not necessarily lead to greater risk but rather, all else being equal, it is the degree of overall supply diversity that drives production cost risk.

Since the notion of excessive risk is inherently a relative rather than absolute notion, Company planners can apply a ranked preference approach whereby a plan is preferred if its expected cost and measured risk are both less than the corresponding values of any competing plan. The ranked preference approach, when it can be applied, does not need to rely on a definition of excessive risk, but only on the principle that customers should prefer a plan that is simultaneously lowest in cost and in risk among competing plans. Thus, for example, the results of the Comprehensive Risk Analysis show that Plan C: Intensity-Based State Average has lower expected cost and risk than any of the other Studied Plans. Plan C: Intensity-Based State Average is superior to all other plans from a mean-variance standpoint without having to characterize any of the competing plans as having excessive risk. On the other hand, comparing Plan A: No CO_2 Limit with Plan B: Intensity-Based Dual Rate shows that Plan B has somewhat lower risk than Plan A, but with a slightly higher expected cost. In this case, which of the two plans should be preferred is not clear. The planner could apply, if known, a customer risk aversion coefficient (a mean-variance utility function) to ultimately determine which plan is preferable. In this instance, however, Plan A is not CPP compliant and would not be preferred on grounds unrelated to risk. It is important to note that the Company does not rely solely on the Comprehensive Risk Analysis in its summary scoring of the Studied Plans. Rather, each plan's measured risk (standard deviation) is entered as one dimension of the Portfolio Evaluation Scorecard presented in Section 6.9.

6.8.5 OPERATING COST RISK ASSESSMENT

The Company analyzed ways to mitigate operating cost risk associated with natural gas-fired generation by use of long-term supply contracts that lock in a stable price, long-term investment in gas reserves, securing long-term firm transportation, and on-site liquefied natural gas storage.

Supply Contract/Investment in Gas Reserves

For the purpose of analyzing long-term supply contracts and long-term investments in gas reserves, the Company utilized stochastic analysis to determine the reduction in volatility that can be achieved by stabilizing prices on various volumes of natural gas. The expected price of natural gas as determined by the stochastic analysis is utilized to stabilize market price for this analysis. To analyze operating cost risk of such price stabilizing arrangements the price of natural gas is "fixed" at the expected value prices for a portion of the total fueling needs. The evaluation measures the reduction in plan risk by comparing the standard deviation between a plan with various quantities of "fixed" price natural gas and the same plan without "fixed" price natural gas. This methodology is representative of measuring the impact a long-term supply contract and/or long-term investment in gas reserves on overall plan risk. In either case, the actions would simulate committing to the purchase of natural gas supply over a long term at prevailing market prices at the time of the transaction. The primary benefit of such a strategy is to stabilize fuel prices, not to ensure below-market prices. Figures 6.8.5.1 – 6.8.5.4 indicate the reduction in portfolio risk associated with various quantities of natural gas at fixed price contracts or a natural gas reserve investment.

Figure 6.8.5.1 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – No Natural Gas at Fixed Price

No Natural Gas At Fixed Price			
Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan A: No CO_2 Limit	$36.35	$4.73	$5.05
Plan B: Intensity-Based Dual Rate	$36.49	$4.69	$4.98
Plan C: Intensity-Based State Average	$35.23	$4.44	$4.70
Plan D: Mass-Based Emissions Cap (existing units only)	$37.41	$4.81	$5.01
Plan E: Mass-Based Emissions Cap (existing and new units)	$40.53	$4.56	$4.82

Figure 6.8.5.2 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 10% of Natural Gas at Fixed Price

10% of Natural Gas at Fixed Price				
Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Limit	$36.77	$4.46	$4.71	5.7%
Plan B: Intensity-Based Dual Rate	$36.94	$4.40	$4.67	6.2%
Plan C: Intensity-Based State Average	$35.63	$4.17	$4.41	6.1%
Plan D: Mass-Based Emissions Cap (existing units only)	$37.79	$4.56	$4.73	5.2%
Plan E: Mass-Based Emissions Cap (existing and new units)	$40.79	$4.36	$4.61	4.3%

Figure 6.8.5.3 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 20% of Natural Gas at Fixed Price

20% of Natural Gas at Fixed Price				
Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Limit	$37.30	$4.19	$4.43	11.3%
Plan B: Intensity-Based Dual Rate	$37.51	$4.11	$4.36	12.3%
Plan C: Intensity-Based State Average	$36.15	$3.90	$4.13	12.2%
Plan D: Mass-Based Emissions Cap (existing units only)	$38.26	$4.31	$4.47	10.3%
Plan E: Mass-Based Emissions Cap (existing and new units)	$41.12	$4.17	$4.39	8.6%

Figure 6.8.5.4 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 30% of Natural Gas at Fixed Price

30% of Natural Gas at Fixed Price				
Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Limit	$37.94	$3.93	$4.14	17.0%
Plan B: Intensity-Based Dual Rate	$38.22	$3.82	$4.06	18.5%
Plan C: Intensity-Based State Average	$36.77	$3.63	$3.84	18.2%
Plan D: Mass-Based Emissions Cap (existing units only)	$38.83	$4.06	$4.19	15.5%
Plan E: Mass-Based Emissions Cap (existing and new units)	$41.51	$3.97	$4.18	12.9%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.8.5.1 – No Gas at Fixed Price analysis.

Included in the analysis of cost and risk mitigation effects of the long-term contracts or reserve investment is an estimate of the price impact the purchase of a large volume of natural gas would have on the market. The cost of such a transaction used in this analysis are representative of the impact on upward price movement that is likely to occur in the market for natural gas with the purchase of a significant quantity of gas on a long-term basis. The market impact of transacting significant volumes on a long-term contract is a function of the amount of time required to execute the contract volume and the price impact/potential movement of the price strip contract during the execution time. The cost of executing a contract of this type is estimated using the price of gas, the daily volatility of the five-year price strip, and the number of days needed to procure the volume. The larger the volume, the longer it takes to execute the transaction, which exposes the total transaction volume to market volatility for a longer period of time and thereby increases the potential for increased cost associated with the transaction. The estimated cost adders included in the analysis are summarized in Figure 6.8.5.5.

Figure 6.8.5.5 – Cost Adders for a Fixed Price Natural Gas Long-Term Contract ($/mmbtu)

		Yearly Volume (Bcf)			
		25	50	75	100
Gas Price	$3.00	$0.11	$0.18	$0.25	$0.32
	$5.00	$0.15	$0.27	$0.39	$0.51
	$7.00	$0.20	$0.37	$0.54	$0.70

The analyzed volumes will have an impact on forward market prices; as such, the Company considers it prudent to include an estimate of the impact of transactions involving large volumes of natural gas on the gas price as a cost adder in this analysis and recognizes the actual impact may be higher or lower than estimated. These costs are presented as representative based on assumptions determined from current market conditions. The salient value to these estimates is the inclusion of estimated market impact verses assuming the transactions can be conducted with no market price impact.

The primary benefit of such a strategy is to mitigate fuel price volatility, not to ensure below market prices. Stable natural gas pricing over the long term does have advantages in terms of rate stability but also carries the risk of higher fuel cost should the market move against the stabilized price. Figures 6.8.5.6 and 6.8.5.7 provide a hypothetical example of stabilizing natural gas price at prevailing market prices available in February of 2011 and February 2012. In this simplified example the assumption is a total fuel volume of 100 million cubic feet ("mmcf") per day is needed for the entire period. The analysis then evaluates the impact of stabilizing the natural gas price, (February 1, 2011 & 2012 forward curve), for 20% of the volume against allowing the total volume to be priced at daily market prices. The key parameter is the cumulative difference between programs that stabilize the price of 20% of the natural gas volume while purchasing 80% of the volume at daily market prices versus purchasing all the natural gas at daily market prices for the entire term. In these examples, the cumulative cost of the natural gas purchased by the 20% fixed cost program are higher by 3% to 11% depending on when the contract was established. These examples indicate that although the use of long-term contracts or reserve investments provides an effective method for mitigating fuel prices volatility, it does not ensure lower fuel cost to the customer.

Figure 6.8.5.6 – Hypothetical Example of the Cost of Purchasing 100 mmcf/d of Natural Gas

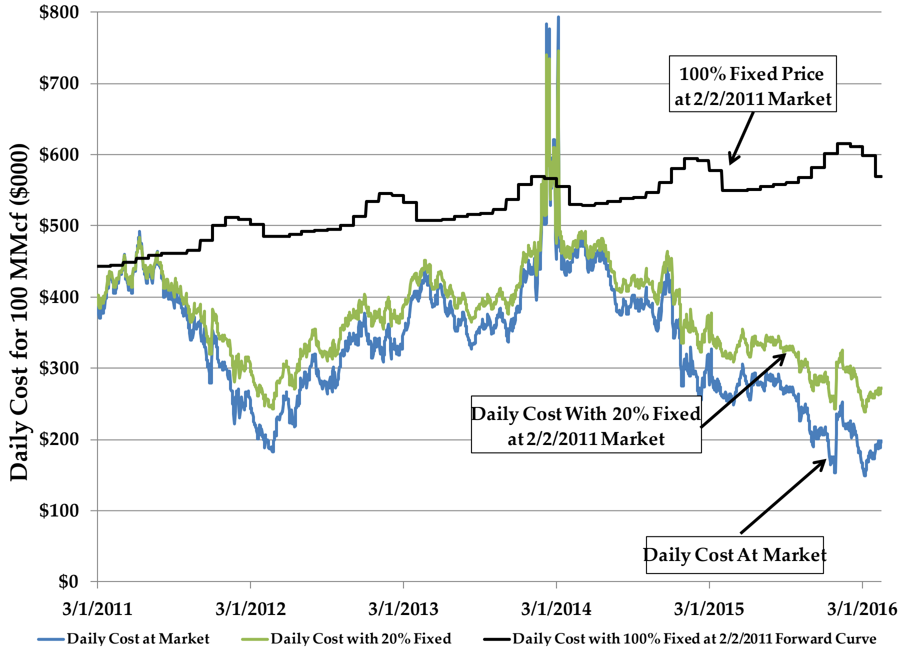
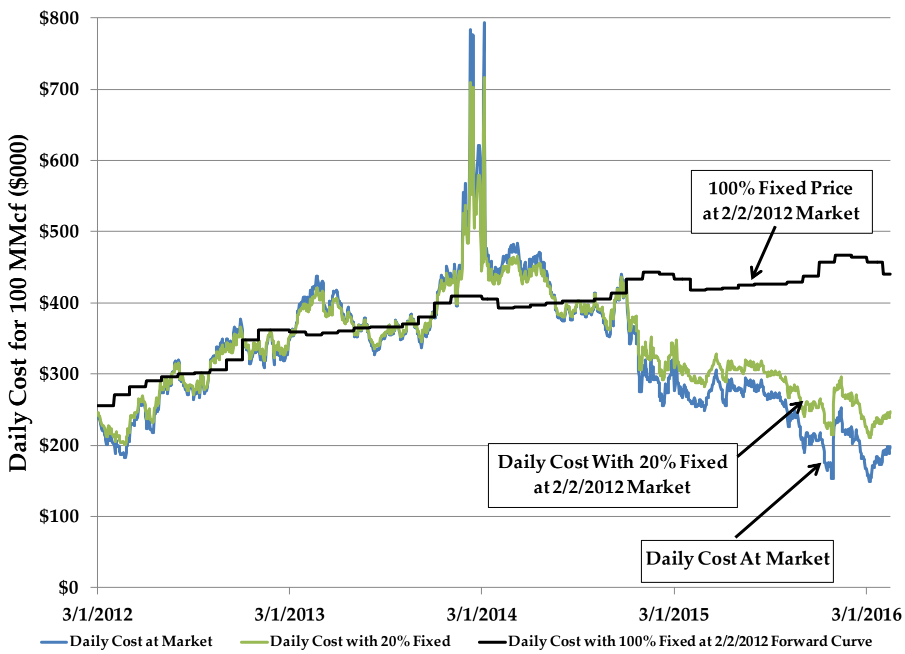


Figure 6.8.5.7 – Hypothetical Example of the Cost of Purchasing 100 mmcf/d of Natural Gas



Note: 100% at Market Price, 100% at Fixed Price and 20% at Fixed Price
Forward Market Price for Henry Hub Gas on February 2, 2011 & 2012

Firm Transportation
To evaluate the risk mitigation impact of securing long-term firm transportation, historic prices were analyzed at two natural gas supply basin trading hubs, Henry Hub and South Point, and at a natural gas trading hub representative of the Company's service territory, Transco Zone 5. The risk mitigation impact is a function of the difference in volatility between various natural gas trading hubs. Pipeline constraints can limit the ability of the pipeline network to move natural gas from supply basins to the market area. These constraints, coupled with weather-driven demand, have historically resulted in significant location specific price volatility for natural gas. Long-term transportation contracts to various supply basin trading hubs affords the opportunity to mitigate location specific volatility risk by having the option to purchase natural gas at trading hubs that have less volatile pricing characteristics. Figure 6.8.5.8 shows the location of key natural gas trading hubs. Figures 6.8.5.9 – 6.8.5.11 illustrate the historic price variations (2009 – 2015) for natural gas at three trading hubs. The shaded area of the graphs indicates one standard deviation of pricing history for each year, meaning that 68% of all daily prices for each year fall within the shaded area. As can be seen in these figures, the historic variations in price differ between the three trading hubs with Transco Zone 5 having a higher variation in natural gas prices than the two trading hubs located in supply basins. Based on historic pricing patterns this would indicate a long-term transportation contract to either Henry Hub or South Point would provide the opportunity to purchase natural gas at a trading hub which has historically experienced less short-term variations in price.

Figure 6.8.5.8 – Map of Key Natural Gas Pipelines and Trading Hubs

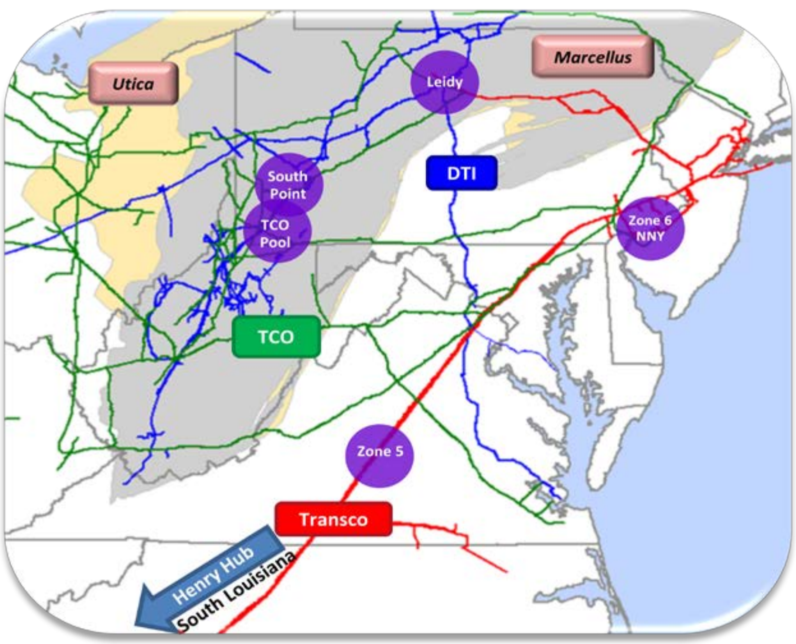
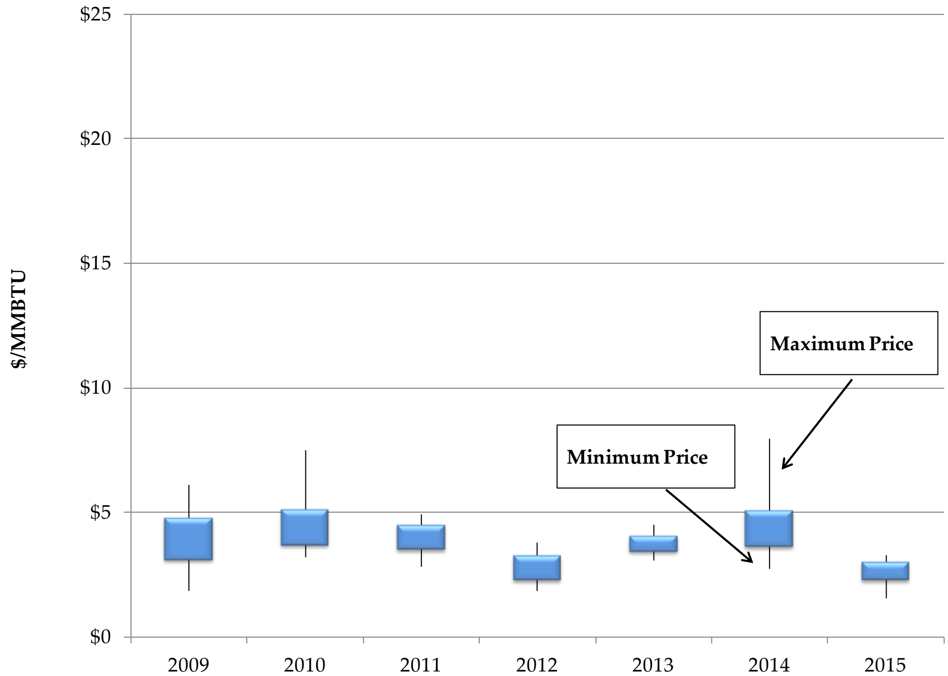
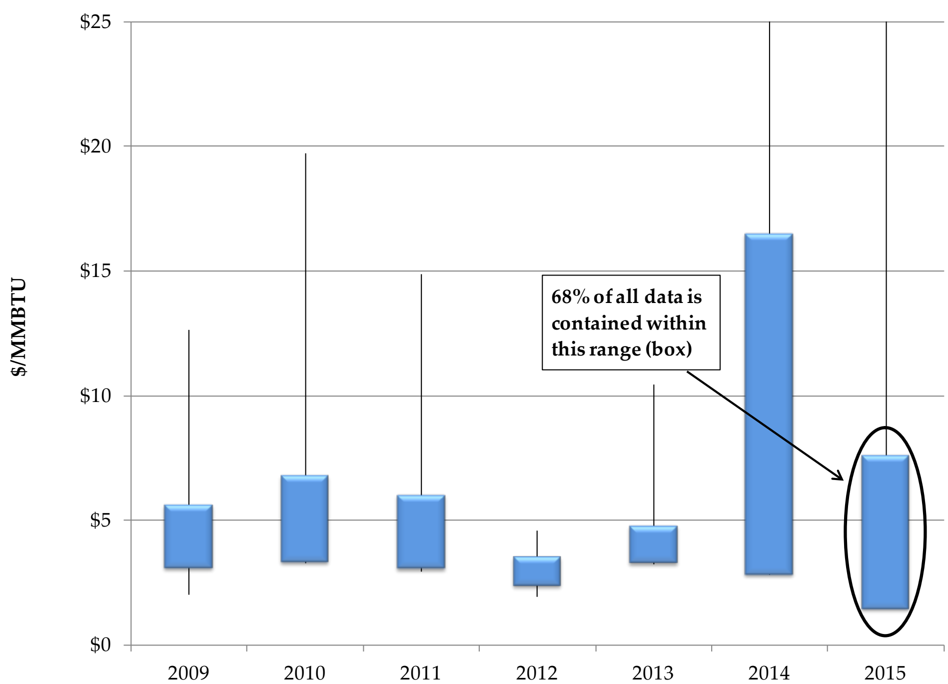


Figure 6.8.5.9 – Natural Gas Daily Average Price Ranges – Henry Hub



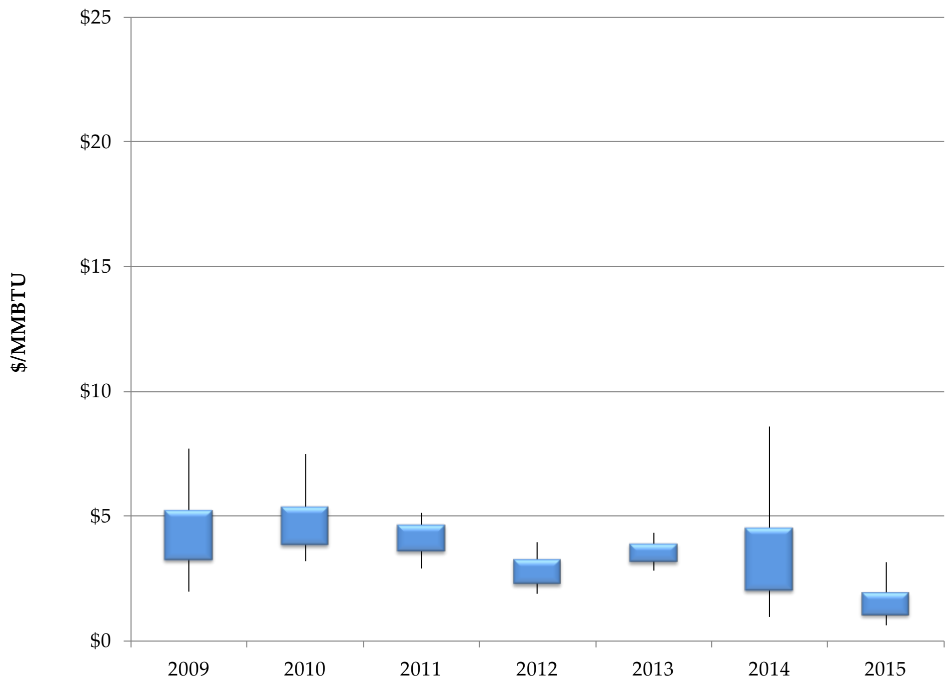
Note: A larger box indicates greater price volatility than a smaller box.

Figure 6.8.5.10 – Natural Gas Daily Average Price Ranges – Transco Zone 5



Note: A larger box indicates greater price volatility than a smaller box.

Figure 6.8.5.11 – Natural Gas Daily Average Price Ranges – South Point



Note: A larger box indicates greater price volatility than a smaller box.

On-site Liquid Natural Gas ("LNG") Storage

On-site LNG storage provides short periods of plant fueling and requires long refill times. It also serves as a backup fueling arrangement capable of mitigating risk associated with a system-wide pipeline disruption scenario while providing an option that has operating characteristics similar to natural gas. However, this type of fueling arrangement provides limited operating cost risk mitigation. The natural gas required to fill LNG storage would be supplied using natural gas purchased at market prices with limited assurance price would be lower during the refill process than when used as a fueling source. LNG storage capacity would generally be large enough to fuel a plant for several days, while taking several months to refill the storage. This provides limited fuel price risk mitigation as the fueling cost for the plant remains exposed to gas market price variability with the exception of the few days the plant can operate on the LNG stored on site. It does provide supply risk mitigation in the event of loss of primary fuel plant fueling.

Risk Mitigation of Gas Generation Displaced by North Anna 3

The Company analyzed the cost of mitigating risk associated with the share of natural gas-fired generation that is equivalent to the amount the Company expects would be displaced by the construction of North Anna 3. An important consideration in this analysis is that in this year's Plan, North Anna 3 is only selected as a resource in Plan E: Mass-Based Emissions Cap (existing and new units). As shown in Chapter 6, (Figure 6.6.3) compliance under Plan E: Mass-Based Emissions Cap (existing and new units) is the highest cost alternative of the Studied Plans, includes 8,000 MW of solar generation, and models the potential retirement of the Company's entire Virginia coal generation fleet. In order to evaluate the risk mitigation associated with replacing North Anna 3 with natural gas-fired generation, stochastic analysis of a test case was developed where North Anna 3 was replaced with natural gas-fired generation with no regards to CPP compliance. Replacing North Anna 3 with natural gas-fired generation would lead to a plan that is non-compliant on a standalone basis with Plan E: Mass-Based Emissions Cap (existing and new units). As discussed in Section 1.4, the Company maintains its "island" approach to trading is prudent for modeling purposes at this time in light of the uncertainty surrounding future markets for ERCs and CO_2 allowances that are not currently in place. Therefore, analysis around the cost of mitigating risk associated with the share of natural gas-fired generation that is equivalent to the amount the Company expects would be displaced by the construction of North Anna 3 was considered for comparative purposes only and not as a CPP compliance option. The analysis indicates this non-compliant test case has higher overall risk than the North Anna 3 compliance scenario, as shown in Figure 6.8.5.12. The higher risk of the non-compliant test case may be mitigated to a level nearly equal to the North Anna 3 compliant plan by price hedging approximately 20% of the natural gas burned by the Company's generation portfolio. However, regardless of the reduction in risk provided by hedging natural gas price, this approach exposes the Company to significant regulatory risk by implementing a plan that is non-compliant with CPP. No amount of natural gas price hedging can mitigate the non-compliance risk associated with replacing North Anna 3 with generation fired by natural gas.

Figure 6.8.5.12 – Risk Assessment of Gas Generation Replacing North Anna 3

	Total Plan Standard Deviation ($/MWh)
Plan E: Mass-Based Emissions Cap (existing units only)	$4.56
Test Case Gas Only	$5.01

Note: Higher standard deviation indicative of higher operating cost risk.

6.9 PORTFOLIO EVALUATION SCORECARD

As discussed in Section 6.1, the Company developed a Portfolio Evaluation Scorecard to provide a quantitative and qualitative measurement system to further examine the Studied Plans compared to Plan A: No CO_2 Limit, which relies primarily on natural gas-fired generation to meet new capacity and energy needs on the Company's system. This analysis combines the results of the Strategist NPV cost results with other quantitative assessment criteria such as Rate Stability (as evaluated through the Comprehensive Risk Analysis along with other criteria).

A brief description of each assessment criteria follows:

Low Cost

This assessment criterion evaluates the Studied Plans according to the results of the Strategist NPV analysis given basecase assumptions. Of the Studied Plans, the lowest NPV cost is assessed a favorable ranking, while the highest cost is assessed an unfavorable ranking.

Rate Stability

Three metrics are reflected under this criterion. The first metric reflects the results of the Comprehensive Risk Analysis using the standard deviation metric. This metric represents the standard deviation in the average energy costs ($/MWh) for each of the Studied Plans and provides a measure of portfolio risk. The Studied Plan with the lowest standard deviation score is assessed a favorable rating, while the plan with the highest standard deviation score is given an unfavorable rating.

The second metric is Capital Investment Concentration. Portfolios that include disproportionate capital expenditures on any single generating unit or facility could increase financial risk to the Company and its customers. In this category, the Studied Plan that includes the highest ratio of a single generating unit or facility's capital spend as compared to the Company's current rate base (approximately $21 billion) will be given an unfavorable rating.

Trading Ready

The third metric is the ability to be Trading Ready. As stated in Chapter 3, the Company favors CPP programs that promote trading of ERCs and/or CO_2 allowances. This is a key aspect of any program because trading provides a clear market price signal, which is the most efficient means of emission mitigation. Also, trading markets offer flexibility in the event of years where a higher level of ERCs or CO_2 allowances are required due to higher than expected fossil generation resulting from weather, or outages of low- or non-emitting generation resources, or both. The Studied Plan with the ability to be trading ready gets a favorable rating, while the plan that is not trading ready gets an unfavorable rating.

Figure 6.9.1 – Portfolio Evaluation Scorecard

Objective	Basecase Cost	Rate Stability		
Period	2016 - 2041			
Portfolio	System Cost Compared to Plan A: No CO_2 Limit (%)	Standard Deviation in Average Energy Cost ($/MWh)	Capital Investment Concentration	Trading Ready
Plan A: No CO_2 Limit	0.0%	4.73	5.2%	N/A
Plan B: Intensity-Based Dual Rate	10.7%	4.69	8.4%	Yes
Plan C: Intensity-Based State Average	12.4%	4.44	8.4%	No
Plan D: Mass-Based Emissions Cap (existing units only)	11.6%	4.81	8.4%	Yes
Plan E: Mass-Based Emissions Cap (existing and new units)	26.6%	4.56	60.1%	Yes

Score rating: Favorable Unfavorable

Figure 6.9.2 – Portfolio Evaluation Scorecard with Scores

Portfolio	System Cost Compared to Plan A: No CO_2 Limit (%)	Standard Deviation in Average Energy Cost ($/MWh)	Capital Investment Concentration	Trading Ready	Total Score
Plan A: No CO_2 Limit	1	0	1	0	2
Plan B: Intensity-Based Dual Rate	0	0	0	1	1
Plan C: Intensity-Based State Average	0	1	0	-1	0
Plan D: Mass-Based Emissions Cap (existing units only)	0	-1	0	1	0
Plan E: Mass-Based Emissions Cap (existing and new units)	-1	0	-1	1	-1

Based on the score rating (Favorable and Unfavorable) illustrated in Figure 6.9.1, scores (1 and -1) were assigned to each Studied Plan. If no favorable or unfavorable rating is provided, then a score of 0 is assigned. Figure 6.9.2 displays the total score for each portfolio. The Scorecard analysis concludes that Plan A: No CO_2 Limit is more favorable compared to the other Studied Plans.

6.10 2016 PLAN

Based on the definition of an "optimal plan" (i.e., least-cost, basecase) set forth in the SCC's 2015 Plan Final Order, Plan A: No CO_2 Limit could be considered optimal if CPP compliance is not necessary, and Plan B: Intensity-Based Dual Rate could be considered optimal if CPP compliance is necessary and Virginia chooses an Intensity-Based SIP consistent with Plan B. However, as mentioned in the Executive Summary, the 2016 Plan offers no "Preferred Plan" or a recommended path forward other than the guidance offered in the Short-Term Action Plan discussed in Chapter 7. Rather, this 2016 Plan offers the Studied Plans, each of which may be a likely path forward once the uncertainty mentioned above is resolved. Plan A: No CO_2 Limit offers a path forward should the CPP be struck down in its entirety (and no replacement carbon legislation or alternative regulation is put in its place). Plans B through E each identify CPP-compliant plans consistent with the four programs that may be adopted by the Commonwealth of Virginia.

The Company plans to further study and assess all reasonable options over the coming year, as the ongoing litigation that is the subject of the Stay Order continues, creating additional uncertainty associated with the CPP's ultimate existence and timing for compliance. At this time and as was the case in the 2015 Plan, the Company is unable to pick a "Preferred Plan" or a recommended path forward beyond the STAP. Rather in compliance with the 2015 Plan Final Order, the Company is presenting the five Studied Plans. The Company believes the Studied Plans represent plausible future paths for meeting the future electric needs of its customers while responding to changing regulatory requirements. Collectively, this analysis and presentation of the Studied Plans, along with the decision to pursue the STAP, comprises the 2016 Plan.

6.11 CONCLUSION

Rather than selecting any single path forward, the Company has created the Studied Plans which, along with the Short-Term Action Plan, are collectively the 2016 Plan. These Studied Plans are being presented to compare and contrast the advantages and risks of each Plan. The Company maintains that it is premature to pick any single long-term strategic path forward until the uncertainty surrounding the CPP diminishes. As discussed in Chapter 1 and this Chapter 6, the Company believes that if the provisions of the CPP are ultimately upheld in their current form, and the model trading rules are finalized as proposed, the adoption of a CPP compliance program consistent with the Dual Rate design identified in the CPP (2016 Plan, Plan B: Intensity-Based Dual Rate) provides the lowest cost option for the Company and its customers and also offers the Commonwealth the most compliance and operational flexibility relative to other likely CPP programs. Conversely, Plan E: Mass-Based Emissions Cap (existing and new units) is the most expensive and constraining program design for a state with an EGU make-up like Virginia, which forecasts economic growth and a capacity deficit position. As shown in Plan E: Mass-Based Emissions Cap (existing and new units), adoption of a program such as this will in all likelihood substantially increase customer rates, and could potentially require the retirement of the Company's entire Virginia coal generation fleet. This type of program design could adversely impact the economic growth potential of Virginia relative to other states and could impose unnecessary economic hardships on the Virginia localities in and around the Company's coal generation facilities.

For the short term, the Company will follow the Short-Term Action Plan presented in Chapter 7. At this time, it is especially important to both the Company and its customers to keep all viable options open and available.

CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2017 – 2021), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2016 Plan. A combination of developments on the market, technological, and regulatory fronts over the next five years will likely shape the future of the Company and the utility industry for decades to come. Not the least of these is the outcome of the ongoing litigation that is the subject of the Supreme Court's Stay Order, which will impact the CPP's ultimate existence and timing for compliance. The Company is proactively positioning itself in the short-term to address these evolving developments for the benefit of all stakeholders over the long-term. Major components of the Company's strategy for the next five years are expected to:

- Enhance and upgrade the Company's existing transmission grid;
- Enhance the Company's access (and deliverability) to natural gas supplies, including shale gas supplies from multiple supply basins;
- Construct additional generation while maintaining a balanced fuel mix;
- Continue to develop and implement a renewable strategy that supports the Virginia RPS goals, the North Carolina REPS requirements, and the CPP;
- Implement cost-effective programs based on measures identified in the DSM Potential Study and continue to implement cost-effective DSM programs in Virginia and North Carolina;
- Add 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020 to set the stage for compliance with the CPP;
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements;
- Enhance reliability and customer service;
- Identify improvements to the Company's infrastructure that will reliably facilitate larger quantities of solar PV generation;
- Continue development of the VOWTAP facility through a stakeholder process; and
- Continue analysis and evaluations for the 20-year nuclear license extensions for Surry Units 1 and 2, and North Anna Units 1 and 2.

Figure 7.1 displays the differences between the 2015 STAP and the 2016 STAP.

Figure 7.1 - Changes between the 2015 and 2016 Short-Term Action Plans

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2016	Brunswick	SLR NUG SPP			~~YT 1-2~~	Approved DSM Proposed DSM
2017		SLR NUG SLR			YT 1-2	
2018		VOWTAP	PP5 - SNCR			
2019	Greensville					
2020		VA SLR[3] SLR			~~YT 3[2], CH 3-4[2], MB1-2[2]~~	
2021		SLR				

Key: Retrofit: Additional environmental control reduction equipment; Retire: Remove a unit from service; Brunswick: Brunswick County Power Station; CH: Chesterfield Power Station; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; PP5: Possum Point Unit 5; Selective Non-Catalytic Reduction; SLR NUG: Solar NUG; SPP: Solar Partnership Program; VA SLR: Generic Solar built in Virginia; YT: Yorktown Unit.

Color Key: Blue: Updated resource since 2015 Plan; Red with Strike: 2015 Plan Resource Replacement.

Note: 1) DSM capacity savings continue to increase throughout the Planning Period.

2) The potential retirements of Chesterfield Units 3 & 4, Mecklenburg Units 1 & 2, and Yorktown Unit 3 are now modeled in 2022, which is outside of the scope of the STAP.

3) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).

A more detailed discussion of the activities over the next five years is provided in the following sections.

7.1 RETIREMENTS

The following planned and modeled retirements are listed in Figure 7.1.1.

Figure 7.1.1 – Generation Retirements

Unit Name	MW Summer	Year Effective
Yorktown 1	159	2017
Yorktown 2	164	2017

Note: Reflects retirement assumptions used for planning purposes, not firm Company commitments.

7.2 GENERATION RESOURCES

- On March 29, 2016, the Greensville County Power Station CPCN was approved by the SCC.
- Continue the reasonable development efforts associated with obtaining the COL for North Anna 3, which is expected in 2017.

- Continue technical evaluations and aging management programs required to support a second period of operation of the Company's existing Surry Units 1 and 2 and North Anna Units 1 and 2.
- Submit an application for the second renewed operating licenses for Surry Units 1 and 2 by the end of the first quarter of 2019.

Figure 7.2.1 lists the generation plants that are currently under construction and are expected to be operational by 2021. Figure 7.2.2 lists the generation plants that are currently under development and are expected to be operational by 2021 subject to SCC approval.

Figure 7.2.1 - Generation under Construction

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)		
					Nameplate	Summer	Winter
2017	Solar Partnership Program	VA	Solar	Intermittent	7	2	2
2019	Greensville County Power Station	VA	Natural Gas	Intermediate/Baseload	1,585	1,585	1,710

Note: 1) Commercial Operation Date.

Figure 7.2.2 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Capacity (Net MW)	
						Summer	Winter
2018	VOWTAP	VA	Wind	Intermittent	12	2	2
2020	VA Solar[2]	VA	Renewable	Intermittent	400	235	235

Note: 1) All Generation under Development projects and planned capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals.
2) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total). Solar PV firm capacity has zero percent value in the first year of operation and increases gradually to 58.7% through 15 years of operation.

Generation Uprates/Derates

Figure 7.2.3 lists the Company's planned changes to existing generating units.

Figure 7.2.3 - Changes to Existing Generation

Unit Name	Type	MW	Year Effective
Bear Garden	GT Upgrade	26	2017
Possum Point 5	SNCR	-	2018

7.3 RENEWABLE ENERGY RESOURCES

Approximately 590 MW of qualifying renewable generation is currently in operation.

Virginia

- Solar Partnership Program 7 MW (nameplate) (8 MW DC) of PV solar DG – is under development and is expected to be complete by 2017.
- 61 MW of biomass capacity at VCHEC by 2021.
- 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).
- Virginia RPS Program – The Company plans to meet its targets by applying renewable generation from existing qualified facilities and purchasing cost-effective RECs.
- Virginia Annual Report – On October 30, 2015, the Company submitted its Annual Report to the SCC, as required, detailing its efforts towards the RPS plan.
- Continue development of VOWTAP.

North Carolina

- North Carolina REPS Compliance Report – The Company achieved its 2014 solar set-aside, poultry waste set-aside and general obligation requirement, which is detailed in its annual REPS Compliance Report submitted on August 19, 2015.
- North Carolina REPS Compliance Plan – The Company submitted its annual REPS Compliance Plan, which is filed as North Carolina Plan Addendum 1 to this integrated resource plan.
- The Company has recently entered into PPAs with approximately 400 MW of North Carolina solar NUGs with estimates of an additional 200 MW by 2017.

Figure 7.3.1 lists the Company's renewable resources.

Figure 7.3.1 - Renewable Resources by 2020

Resource	Nameplate MW	Plan A: No CO_2 Limit	Compliant with the Clean Power Plan			
			Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass- Based Emissions Cap (existing and new units)
Existing Resources	590	x	x	x	x	x
Additional VCHEC Biomass	27	x	x	x	x	x
Solar Partnership Program	7	x	x	x	x	x
Solar NUGs	600	x	x	x	x	x
VA Solar[1]	400	x	x	x	x	x
VOWTAP	12	x	x	x	x	x
Solar 2020	-	-	200 MW	400 MW	200 MW	800 MW

Note: 1) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).

7.4 TRANSMISSION

Virginia

The following planned Virginia transmission projects detailed in Figure 7.4.1 are pending SCC approval or are tentatively planned for filing with the SCC:

- Elmont – Cunningham 500 kV Line Rebuild;
- Mosby – Brambleton 500 kV Line;
- Norris Bridge 115 kV Rebuild;
- Cunningham-Dooms 500 kV Rebuild;
- 230 kV Line and new Pacific Substation;
- 230 kV Line and new Haymarket Substation;
- 230 kV Line and new Poland Road Substation;
- 230 kV Line and new Yardley Ridge Switching Station; and
- 230 kV Line and Idylwood to Scotts Run Substation.

Figure 7.4.1 lists the major transmission additions including line voltage and capacity, expected operation target dates.

Figure 7.4.1 - Planned Transmission Additions

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
New 115kV DP to Replace Pointon 34.5kV DP - SEC	115	230	May-16	VA
Line #2090 Uprate	230	1,129	May-16	VA
Loudoun – Pleasant View Line #558 Rebuild	500	4,000	May-16	VA
Line #2157 Reconductor and Upgrade (Fredericksburg - Cranes Corner)	230	1,047	May-16	VA
Rebuild Line #2027 (Bremo - Midlothian)	230	1,047	May-16	VA
230kV Line Extension to new Pacific Substation	230	1,047	May-16	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Jun-16	VA
Line #22 Rebuild Carolina - Eatons Ferry	115	262	Jun-16	NC
Line #54 Reconductor - Carolina - Woodland	115	306	Jun-16	NC
New 230kV Line Dooms to Lexington	230	1,047	Jun-16	VA
Line #87 Rebuild from Chesapeake to Churchland	115	239	Jun-16	VA
Burton Switching Station and 115 kV Line to Oakwood	115	233	Jun-16	VA
Line #1 Rebuild - Crewe to Fort Pickett DP	115	261	Dec-16	VA
Line #33 Rebuild and Halifax 230kV Ring Bus	115	353	Dec-16	VA
Line #18 and Line #145 Rebuild	115	524	Dec-16	VA
Line #4 Rebuild Between Bremo and Structure #8474	115	151	Dec-16	VA
Surry - Skiffes Creek 500 kV Line	500	4,325	Apr-17	VA
Skiffes Creek - Whealton 230 kV Line	230	1,047	Apr-17	VA
*Line #2161 Wheeler to Gainesville (part of Warrenton project)	230	1,047	May-17	VA
*Line #2174 Vint Hill to Wheeler (part of Warrenton project)	230	1,047	May-17	VA
Line #69 Uprate Reams DP to Purdy	115	300	Jun-17	VA
Line #82 Rebuild - Everetts to Voice of America	115	261	Dec-17	NC
Line #65 - Remove from the Whitestone Bridge	115	147	Dec-17	VA
*Network Line 2086 from Warrenton	230	1,047	May-18	VA
*230kV Line Extension to new Haymarket Substation	230	1,047	May-18	VA
Line #47 Rebuild (Kings Dominion to Fredericksburg)	115	353	May-18	VA
Line #47 Rebuild (Four Rivers to Kings Dominion)	115	353	May-18	VA
Line #159 Reconductor and Uprate	115	353	May-18	VA
*Idylwood to Scotts Run – New 230kV Line and Scotts Run Substation	230	1,047	May-18	VA
Relocate Line #4 Load	115	151	May-18	VA
230kV Line Extension to new Yardley Ridge DP	230	1,047	May-18	VA
230kV Line Extension to new Poland Road Sub	230	1,047	May-18	VA
Line #553 (Cunningham to Elmont) Rebuild and Uprate	500	4,000	Jun-18	VA
Brambleton to Mosby 2nd 500kV Line	500	4,000	Jun-18	VA
Line #48 and #107 Partial Rebuild	115	317 (#48)	Dec-18	VA
Line #34 and Line #61 (partial) Rebuild	115	353 (#34)	Dec-18	VA
Line #2104 Reconductor and Upgrade (Cranes Corner - Stafford)	230	1,047	May-19	VA
New 230kV Line Remington to Gordonsville	230	1,047	Jun-19	VA
Rebuild Cunningham - Dooms (Line #534) 500 kV Line	500	4,453	Jun-19	VA
Line #27 and #67 Rebuild from Greenwich to Burton	115	262	Dec-19	VA
* 230kV Line Extension to new Harry Byrd Sub	230	1,047	May-20	VA

Note: Asterisk reflects planned transmission addition subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s).

7.5 DEMAND-SIDE MANAGEMENT

The Company continues to evaluate the measures identified in the DSM Potential Study and may include additional measures in DSM programs in future integrated resource plans. The measures included in the DSM Potential Study still need to be part of a program design effort that looks at the viability of the potential measures as a single or multi-measure DSM program. These fully-designed DSM programs would also need to be evaluated for cost effectiveness.

The Company is also still continuing to monitor the status of the CPP rules and reviewing the Final Rule in light of this uncertain status. While it is unclear at this point what level of DSM the Virginia and North Carolina State Plans may require, or what impact the ongoing litigation that is the subject of the Stay Order will have on the existence and timing of the CPP, the Company will continue to evaluate potential increased levels of DSM as a means of meeting the CPP requirements.

Virginia

The Company will continue its analysis of future programs and may file for approval of new or revised programs that meet the Company requirements for new DSM resources in August 2016. The Company filed its "Phase V" DSM Application on August 28, 2015, seeking approval of two new energy efficiency DSM programs: Residential Programmable Thermostat Program and Small Business Improvement Program (Case No. PUE-2015-00089). In addition, the Company filed for continuation of the Phase I AC Cycling Program. On April 19, 2016, the Commission issued its Final Order approving the Small Business Improvement Program and the Air Conditioner Cycling Program, subject to certain conditions, and denying the Residential Programmable Thermostat Program.

North Carolina

The Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that have been approved in Virginia that continue to meet the Company requirements for new DSM resources. On July 31, 2015, the Company filed for NCUC approval of the Income and Age Qualifying Home Improvement Program that was approved in Virginia in Case No. PUE-2014-00071. On October 6, 2015, the NCUC approved this new DSM program.

Figure 7.5.1 lists the projected demand and energy savings by 2021 from the approved and proposed DSM programs.

Figure 7.5.1 - DSM Projected Savings By 2021

Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Air Conditioner Cycling Program	121	-	Approved/Approved
Residential Low Income Program	2	10	Completed/Completed
Residential Lighting Program	3	36	
Commercial Lighting Program	5	45	Closed/Closed
Commercial HVAC Upgrade	1	4	
Non-Residential Distributed Generation Program	16	0	Approved/Rejected
Non-Residential Energy Audit Program	9	68	Approved/Approved
Non-Residential Duct Testing and Sealing Program	26	69	
Residential Bundle Program	32	211	
Residential Home Energy Check-Up Program	4	19	
Residential Duct Sealing Program	2	11	
Residential Heat Pump Tune Up Program	11	78	
Residential Heat Pump Upgrade Program	15	103	
Non-Residential Window Film Program	18	79	
Non-Residential Lighting Systems & Controls Program	30	108	
Non-Residential Heating and Cooling Efficiency Program	21	33	
Income and Age Qualifying Home Improvement Program	4	16	
Residential Appliance Recycling Program	6	34	Approved/No Plans
Residential Programmable Thermostat Program	2	6	Rejected/No Plans
Small Business Improvement Program	18	64	Approved/Under Evaluation

Advanced Metering Infrastructure

The Company has AMI, or smart meters, on homes and businesses in areas throughout Virginia. The AMI meter upgrades are part of an on-going demonstration effort that will help the Company further evaluate the effectiveness of AMI meters in achieving voltage optimization, voltage stability, remotely turning off and on electric service, power outage and restoration detection and reporting, remote daily meter readings, and offering dynamic rates.

The Company has projected, in prior Plans, the potential energy savings associated with voltage conservation as a DSM program. The objective of voltage conservation is to conserve energy by reducing voltage for residential, commercial and industrial customers served within the allowable range. Voltage conservation is enabled through the deployment of AMI. Given that the Company has not yet decided on full deployment of AMI, the Company has removed Voltage Conservation energy reductions from this 2016 Plan.

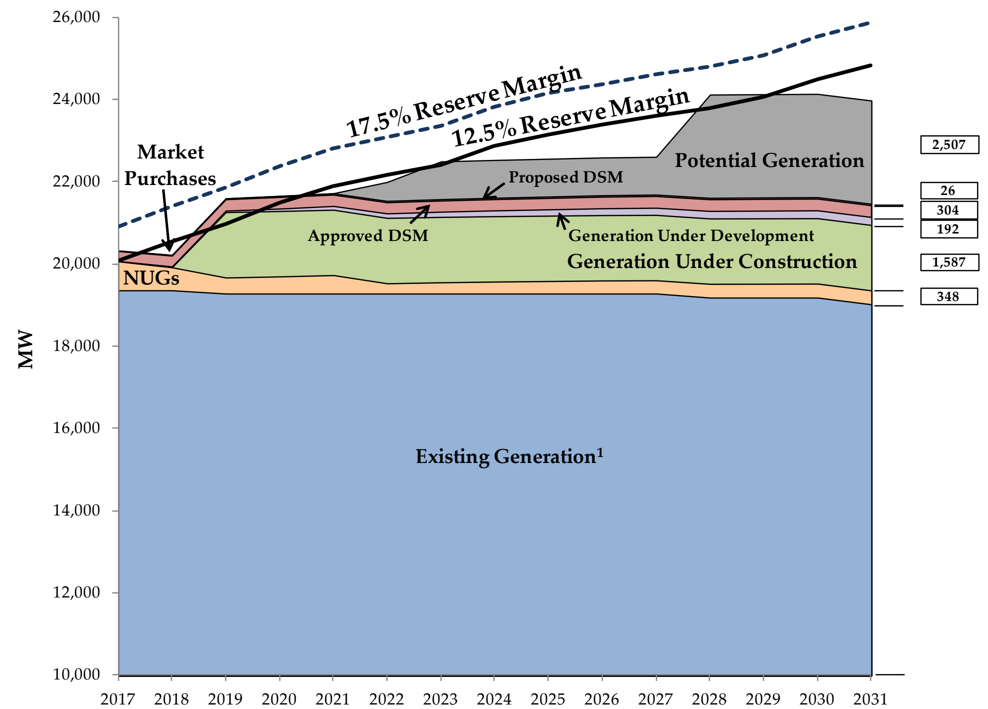
More study is required with respect to how voltage conservation will integrate with intermittent generation resources, like solar and wind, on the distribution and transmission systems.

The Company currently has several activities underway that will provide insight into how the Company can integrate increasing amounts of solar generation on the transmission and distribution grid while maintaining reliable service to our customers with proper voltage, frequency, and system protection.

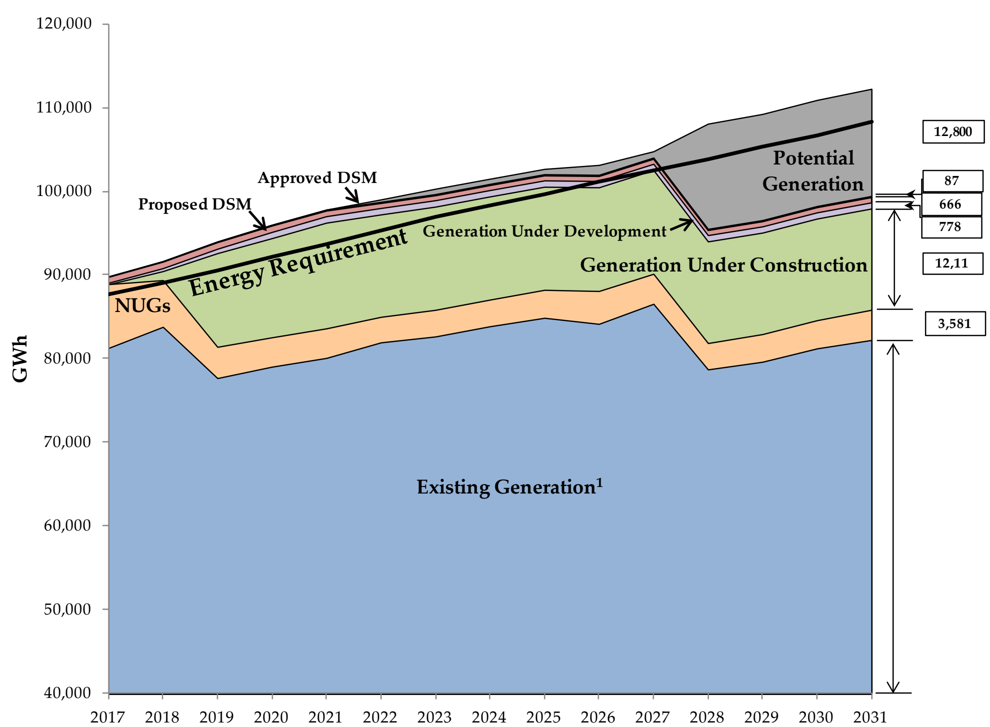
APPENDIX

Appendix 1A – Plan A: No CO_2 Limit – Capacity & Energy

Capacity



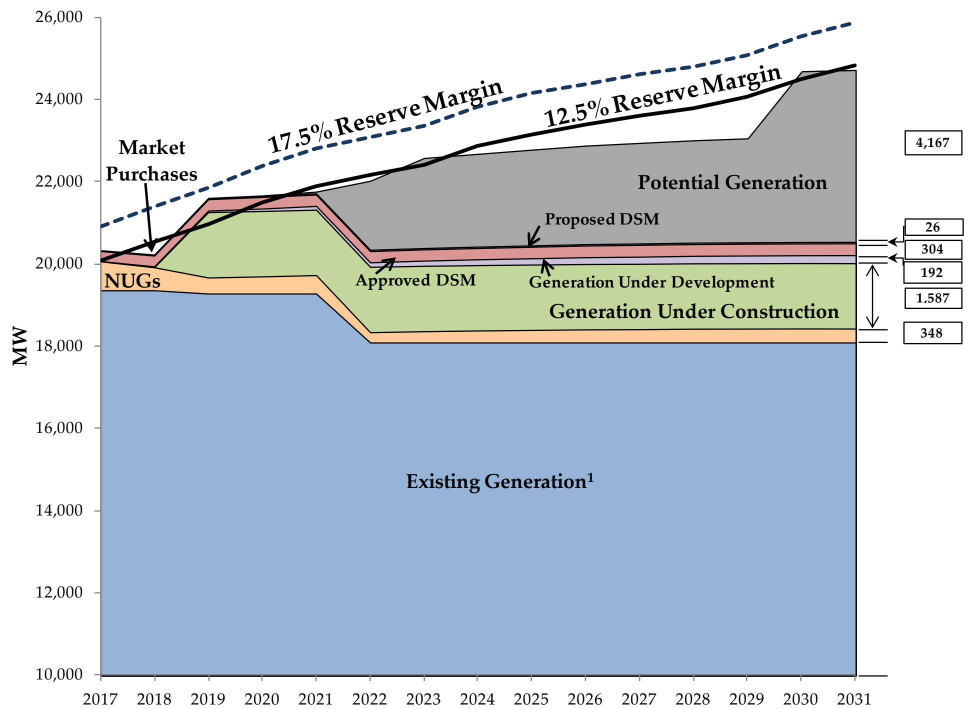
Energy



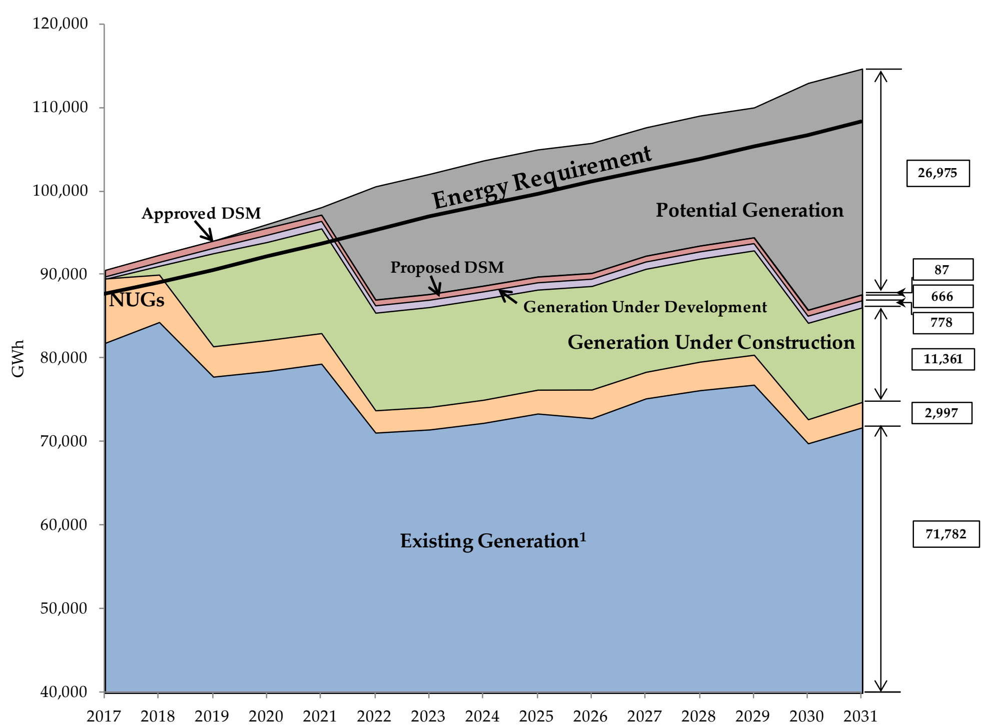
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan B: Intensity-Based Dual Rate – Capacity & Energy

Capacity



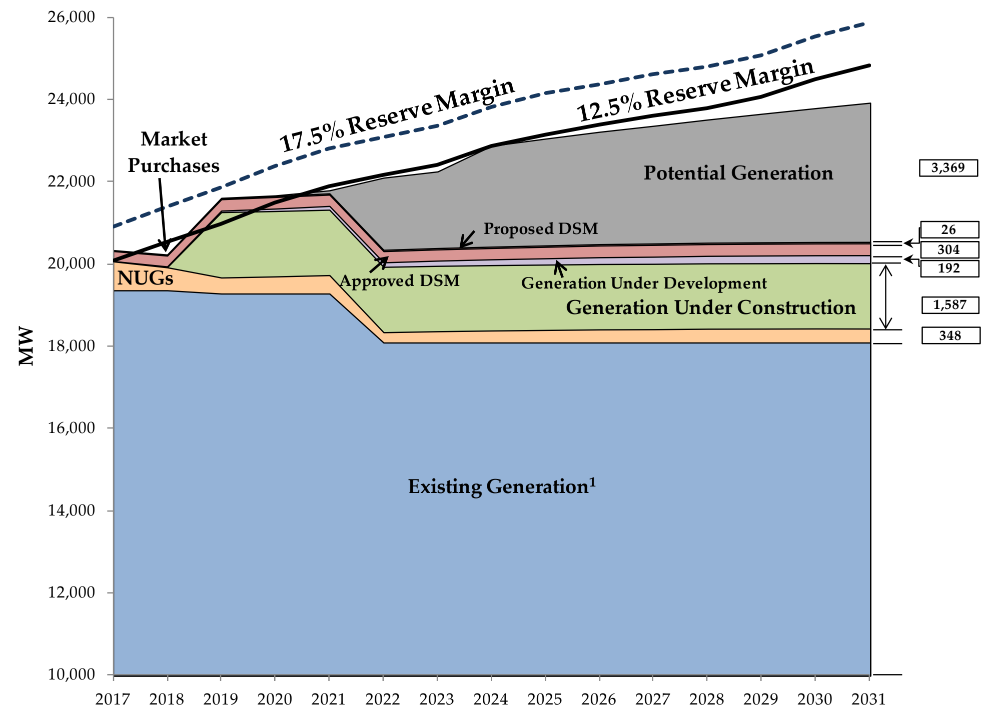
Energy



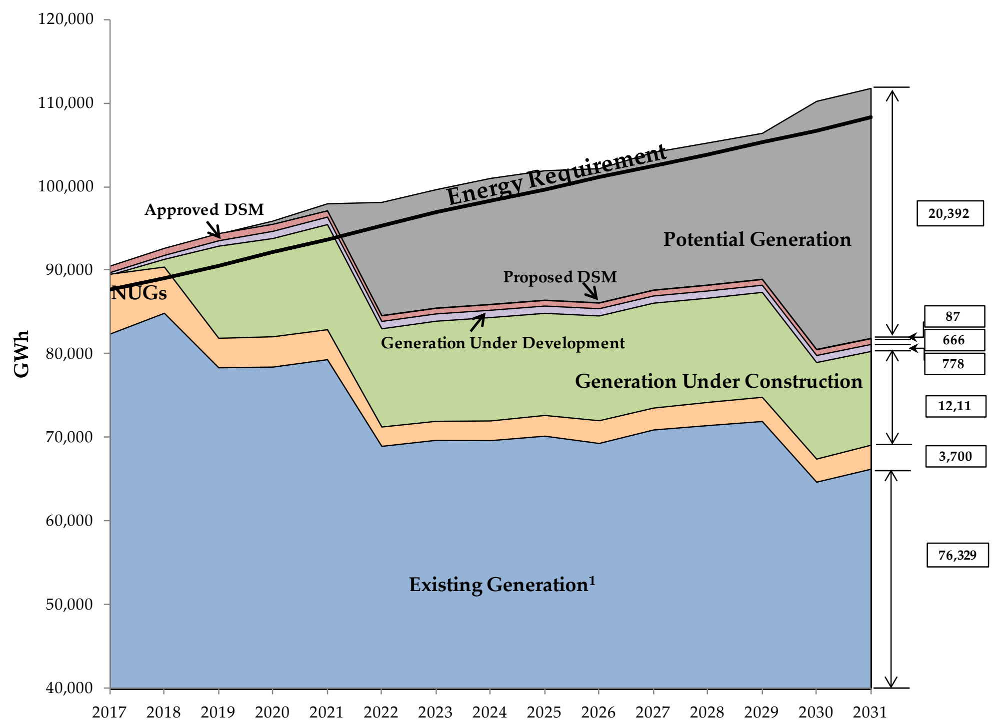
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan C: Intensity-Based State Average – Capacity & Energy

Capacity



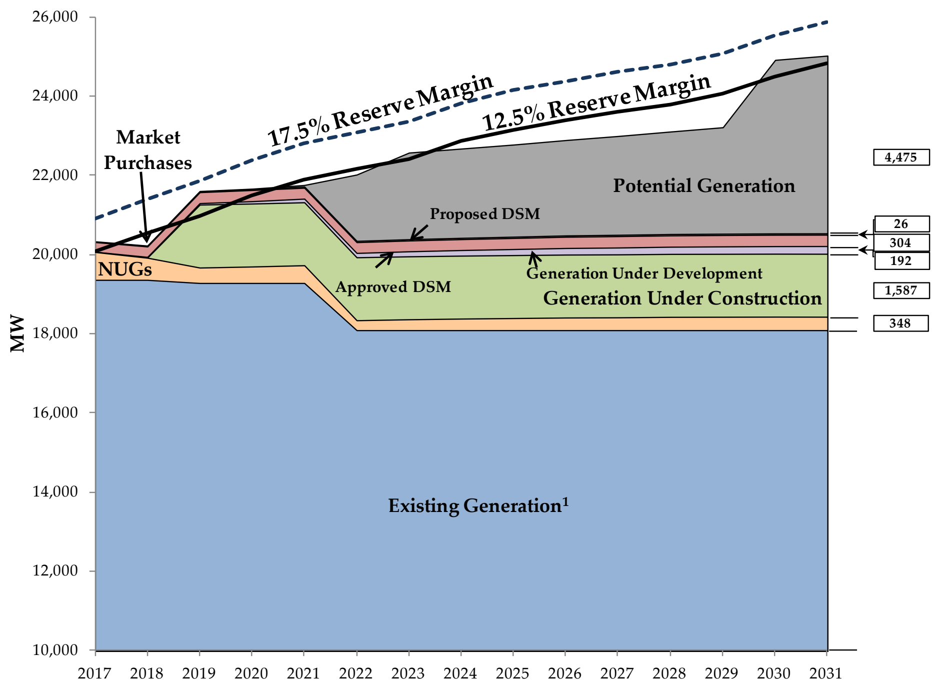
Energy



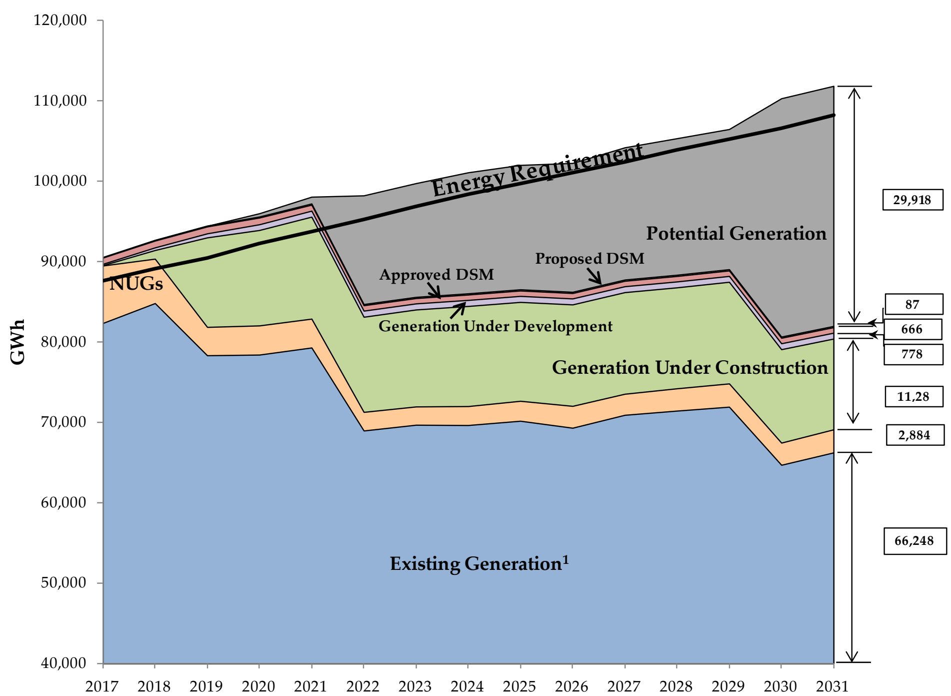
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan D: Mass-Based Emissions Cap (existing units only) – Capacity & Energy

Capacity



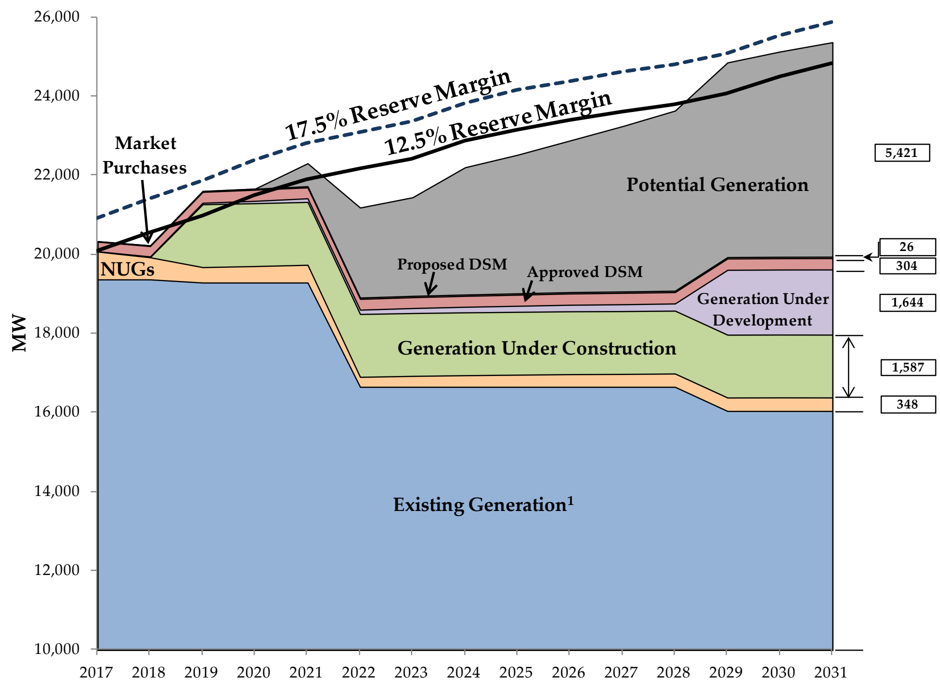
Energy



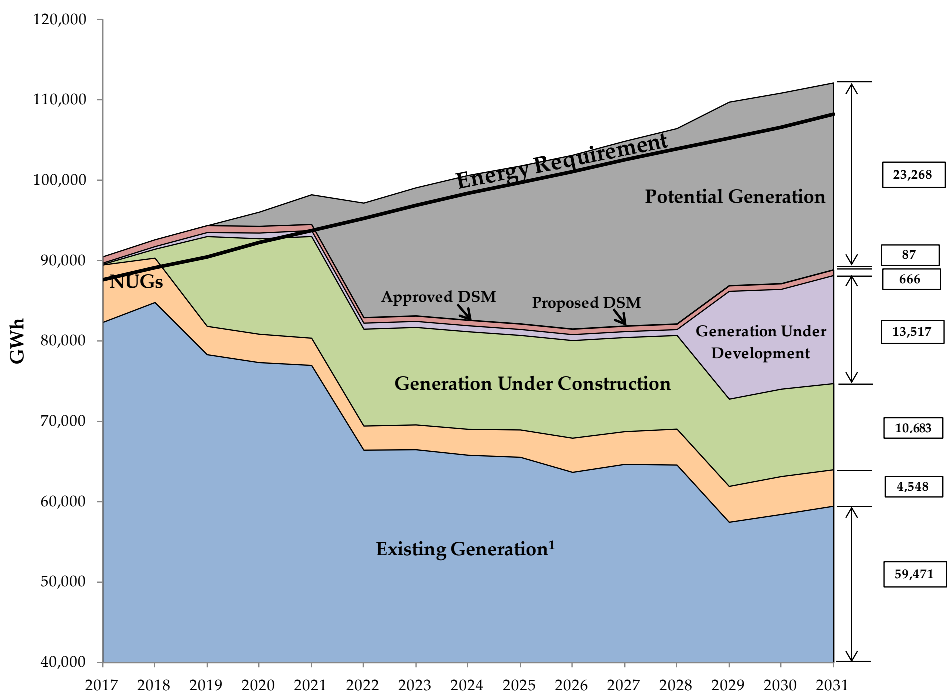
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan E: Mass-Based Emissions Cap (existing and new units) – Capacity & Energy

Capacity



Energy



Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 2A – Total Sales by Customer Class
(DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	28,544	27,078	10,168	10,040	282	2,216	78,327
2007	30,469	28,416	10,094	10,660	283	1,778	81,700
2008	29,646	28,484	9,779	10,529	282	1,841	80,561
2009	29,904	28,455	8,644	10,448	276	1,995	79,721
2010	32,547	29,233	8,512	10,670	281	1,926	83,169
2011	30,779	28,957	7,960	10,555	273	1,909	80,434
2012	29,174	28,927	7,849	10,496	277	1,980	78,704
2013	30,184	29,372	8,097	10,261	276	2,013	80,203
2014	31,290	29,964	8,812	10,402	261	1,947	82,676
2015	30,923	30,282	8,765	10,159	275	1,961	82,364
2016	30,683	31,037	8,422	10,362	294	1,531	82,329
2017	31,013	32,383	8,342	10,444	298	1,529	84,009
2018	31,550	33,540	8,250	10,474	302	1,532	85,648
2019	32,019	34,253	8,193	10,501	307	1,538	86,811
2020	32,529	34,998	8,160	10,559	311	1,551	88,108
2021	32,942	35,854	8,083	10,650	316	1,560	89,405
2022	33,835	37,016	7,743	10,969	321	1,569	91,453
2023	34,307	37,954	7,704	11,123	326	1,579	92,991
2024	34,923	38,858	7,691	11,231	331	1,594	94,628
2025	35,347	39,785	7,662	11,240	335	1,602	95,972
2026	35,854	40,862	7,635	11,340	340	1,615	97,646
2027	36,342	41,725	7,622	11,405	344	1,628	99,066
2028	36,971	42,641	7,627	11,507	348	1,646	100,739
2029	37,376	43,392	7,579	11,638	352	1,656	101,992
2030	37,928	44,196	7,571	11,761	356	1,670	103,483
2031	38,467	45,135	7,553	11,868	360	1,684	105,068

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2B– Virginia Sales by Customer Class
(DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	27,067	26,303	8,404	9,903	274	2,171	74,122
2007	28,890	27,606	8,359	10,519	274	1,735	77,385
2008	28,100	27,679	8,064	10,391	273	1,754	76,261
2009	28,325	27,646	7,147	10,312	268	1,906	75,604
2010	30,831	28,408	6,872	10,529	273	1,877	78,791
2011	29,153	28,163	6,342	10,423	265	1,860	76,206
2012	27,672	28,063	6,235	10,370	269	1,928	74,538
2013	28,618	28,487	6,393	10,134	267	1,962	75,861
2014	29,645	29,130	6,954	10,272	253	1,897	78,151
2015	29,293	29,432	7,006	10,029	266	1,911	77,937
2016	29,014	30,172	6,647	10,231	285	1,484	77,833
2017	29,328	31,510	6,553	10,313	289	1,472	79,465
2018	29,851	32,660	6,447	10,342	294	1,475	81,068
2019	30,308	33,367	6,376	10,367	298	1,479	82,195
2020	30,807	34,105	6,328	10,424	303	1,492	83,459
2021	31,210	34,956	6,237	10,514	307	1,500	84,723
2022	32,056	36,088	5,974	10,829	312	1,508	86,768
2023	32,503	37,002	5,944	10,981	317	1,518	88,265
2024	33,087	37,884	5,934	11,088	322	1,533	89,847
2025	33,488	38,788	5,912	11,097	326	1,541	91,151
2026	33,969	39,838	5,891	11,195	330	1,553	92,776
2027	34,431	40,679	5,881	11,260	334	1,565	94,151
2028	35,027	41,573	5,885	11,360	338	1,582	95,765
2029	35,411	42,304	5,847	11,489	342	1,592	96,986
2030	35,934	43,088	5,842	11,611	346	1,606	98,427
2031	36,444	44,004	5,828	11,717	350	1,619	99,962

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2C – North Carolina Sales by Customer Class
(DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	1,477	775	1,763	137	8	45	4,205
2007	1,579	810	1,735	140	8	43	4,315
2008	1,546	806	1,715	138	8	87	4,300
2009	1,579	809	1,497	136	8	89	4,118
2010	1,716	825	1,640	141	8	49	4,378
2011	1,626	795	1,618	132	8	49	4,228
2012	1,502	864	1,614	126	8	52	4,167
2013	1,567	885	1,704	127	8	51	4,342
2014	1,645	834	1,858	130	8	50	4,525
2015	1,630	850	1,759	130	8	50	4,428
2016	1,670	866	1,775	131	8	47	4,496
2017	1,685	873	1,789	132	8	57	4,544
2018	1,699	880	1,803	133	9	58	4,581
2019	1,711	887	1,818	134	9	59	4,616
2020	1,721	893	1,832	135	9	59	4,649
2021	1,732	899	1,846	136	9	60	4,682
2022	1,779	928	1,769	140	9	60	4,685
2023	1,804	951	1,760	142	9	61	4,727
2024	1,836	974	1,757	143	9	61	4,781
2025	1,859	997	1,750	143	9	62	4,820
2026	1,885	1,024	1,744	145	9	62	4,870
2027	1,911	1,046	1,741	146	10	63	4,916
2028	1,944	1,069	1,742	147	10	63	4,975
2029	1,965	1,088	1,731	149	10	64	5,006
2030	1,994	1,108	1,730	150	10	64	5,056
2031	2,023	1,131	1,725	151	10	65	5,106

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2D – Total Customer Count
(DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	2,072,726	223,961	635	28,540	2,356	5	2,328,223
2007	2,102,751	227,829	620	28,770	2,347	5	2,362,321
2008	2,124,089	230,715	598	29,008	2,513	5	2,386,927
2009	2,139,604	232,148	581	29,073	2,687	4	2,404,098
2010	2,157,581	232,988	561	29,041	2,798	3	2,422,972
2011	2,171,795	233,760	535	29,104	3,031	3	2,438,227
2012	2,187,670	234,947	514	29,114	3,246	3	2,455,495
2013	2,206,657	236,596	526	28,847	3,508	3	2,476,138
2014	2,229,639	237,757	631	28,818	3,653	3	2,500,500
2015	2,252,438	239,623	662	28,923	3,814	3	2,525,463
2016	2,274,642	241,443	655	29,259	3,959	3	2,549,962
2017	2,297,629	243,876	654	29,347	4,103	3	2,575,613
2018	2,329,147	246,603	653	29,446	4,247	3	2,610,099
2019	2,361,108	249,366	652	29,542	4,391	3	2,645,062
2020	2,392,285	252,078	651	29,625	4,535	3	2,679,177
2021	2,423,934	254,815	650	29,698	4,679	3	2,713,780
2022	2,456,812	257,630	649	29,767	4,823	3	2,749,684
2023	2,490,228	260,481	648	29,833	4,967	3	2,786,160
2024	2,522,891	263,288	647	29,893	5,111	3	2,821,834
2025	2,553,969	265,998	646	29,945	5,255	3	2,855,816
2026	2,583,527	268,610	645	29,989	5,399	3	2,888,173
2027	2,612,057	271,157	644	30,025	5,543	3	2,919,430
2028	2,639,880	273,660	643	30,057	5,687	3	2,949,929
2029	2,667,111	276,125	642	30,084	5,831	3	2,979,797
2030	2,693,943	278,565	641	30,107	5,975	3	3,009,234
2031	2,722,640	278,769	641	30,109	5,981	3	3,038,143

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2E – Virginia Customer Count
(DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	1,973,430	208,556	566	26,654	1,994	3	2,211,202
2007	2,002,884	212,369	554	26,896	1,971	3	2,244,676
2008	2,023,592	215,212	538	27,141	2,116	3	2,268,602
2009	2,038,843	216,663	522	27,206	2,290	2	2,285,525
2010	2,056,576	217,531	504	27,185	2,404	2	2,304,202
2011	2,070,786	218,341	482	27,252	2,639	2	2,319,502
2012	2,086,647	219,447	464	27,265	2,856	2	2,336,680
2013	2,105,500	221,039	477	26,996	3,118	2	2,357,131
2014	2,128,313	222,143	579	26,966	3,267	2	2,381,269
2015	2,150,818	223,946	611	27,070	3,430	2	2,405,877
2016	2,172,587	225,816	594	27,408	3,567	2	2,429,974
2017	2,195,304	228,214	593	27,499	3,710	2	2,455,322
2018	2,226,450	230,901	592	27,601	3,853	2	2,489,400
2019	2,258,035	233,625	592	27,700	3,996	2	2,523,950
2020	2,288,846	236,297	591	27,785	4,140	2	2,557,661
2021	2,320,122	238,995	590	27,861	4,283	2	2,591,853
2022	2,352,614	241,769	589	27,932	4,426	2	2,627,332
2023	2,385,637	244,580	588	27,999	4,569	2	2,663,374
2024	2,417,915	247,347	587	28,061	4,712	2	2,698,624
2025	2,448,628	250,017	586	28,115	4,856	2	2,732,203
2026	2,477,838	252,592	585	28,160	4,999	2	2,764,175
2027	2,506,032	255,102	584	28,198	5,142	2	2,795,060
2028	2,533,527	257,569	583	28,230	5,285	2	2,825,196
2029	2,560,439	259,998	582	28,258	5,429	2	2,854,708
2030	2,586,955	262,403	581	28,282	5,572	2	2,883,795
2031	2,615,314	262,604	581	28,284	5,578	2	2,912,363

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2F – North Carolina Customer Count
(DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2006	99,296	15,406	69	1,886	363	2	117,021
2007	99,867	15,460	66	1,874	376	2	117,645
2008	100,497	15,502	60	1,867	397	2	118,325
2009	100,761	15,485	59	1,867	398	2	118,573
2010	101,005	15,457	56	1,857	395	1	118,771
2011	101,009	15,418	53	1,852	392	1	118,725
2012	101,024	15,501	50	1,849	390	1	118,815
2013	101,158	15,557	50	1,851	390	1	119,007
2014	101,326	15,614	52	1,853	386	1	119,231
2015	101,620	15,677	52	1,853	384	1	119,586
2016	102,055	15,627	61	1,851	392	1	119,987
2017	102,326	15,662	61	1,848	393	1	120,291
2018	102,696	15,702	61	1,845	394	1	120,699
2019	103,072	15,741	61	1,842	395	1	121,112
2020	103,439	15,780	61	1,840	395	1	121,516
2021	103,812	15,820	61	1,837	396	1	121,927
2022	104,198	15,860	61	1,835	397	1	122,353
2023	104,591	15,901	61	1,833	398	1	122,786
2024	104,976	15,942	61	1,832	399	1	123,209
2025	105,341	15,981	60	1,830	399	1	123,613
2026	105,689	16,018	60	1,829	400	1	123,998
2027	106,025	16,055	60	1,828	401	1	124,370
2028	106,352	16,091	60	1,827	402	1	124,733
2029	106,673	16,127	60	1,826	402	1	125,089
2030	106,988	16,162	60	1,825	403	1	125,440
2031	107,326	16,165	60	1,825	403	1	125,780

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2G – Zonal Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2006	19,375	16,243
2007	19,688	18,079
2008	19,051	17,028
2009	18,137	17,904
2010	19,140	17,689
2011	20,061	17,889
2012	19,249	16,881
2013	18,763	17,623
2014	18,692	19,784
2015	18,980	21,651
2016	20,127	18,090
2017	20,562	18,418
2018	20,995	18,601
2019	21,418	18,919
2020	21,847	19,192
2021	22,263	19,453
2022	22,546	19,807
2023	22,792	20,005
2024	23,260	20,136
2025	23,566	20,523
2026	23,792	20,776
2027	24,016	21,164
2028	24,201	21,555
2029	24,482	21,588
2030	24,919	21,874
2031	25,249	22,162

Note: Historic (2006 – 2015), Projected (2016 – 2031).

Appendix 2H – Summer & Winter Peaks for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 5**

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)															
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,469	16,348	16,530	17,147	17,207	17,578	17,835	18,891	19,257	19,509	19,724	20,132	20,399	20,597	20,792	20,953	21,197	21,579	21,866
b. Other Commitments(2)	-103	-99	71	473	794	802	915	234	232	229	229	230	231	232	233	233	235	236	237
c. Total System Summer Peak	16,366	16,249	16,601	17,620	18,001	18,379	18,750	19,125	19,490	19,738	19,952	20,362	20,630	20,828	21,024	21,186	21,432	21,814	22,103
d. Percent Increase in Total Summer Peak	-4.2%	-0.7%	2.2%	6.1%	2.2%	2.1%	2.0%	2.0%	1.9%	1.3%	1.1%	2.1%	1.3%	1.0%	0.9%	0.8%	1.2%	1.8%	1.3%
2. Winter																			
a. Adjusted Winter Peak(1)	15,209	16,939	18,617	15,611	15,894	16,046	16,317	16,548	16,774	17,080	17,250	17,362	17,698	17,916	18,250	18,588	18,615	18,862	19,110
b. Other Commitments(2)	-103	-99	71	0.6	3	6	10	14	15	15	15	15	15	15	16	16	16	16	16
c. Total System Winter Peak	15,106	16,840	18,688	15,611	15,896	16,053	16,327	16,562	16,788	17,095	17,265	17,377	17,713	17,931	18,266	18,604	18,631	18,878	19,126
d. Percent Increase in Total Winter Peak	-4.6%	11.5%	11.0%	-16.5%	1.8%	1.0%	1.7%	1.4%	1.4%	1.8%	1.0%	0.7%	1.9%	1.2%	1.9%	1.8%	0.1%	1.3%	1.3%

(1) Adjusted load from Appendix 2I.

(2) Includes firm Additional Forecast, Conservation Efficiency, and Peak Adjustments from Appendix 2I.

Appendix 2I – Projected Summer & Winter Peak Load & Energy Forecast for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]				(PROJECTED)														
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,366	16,249	16,530	17,620	18,001	18,379	18,750	19,125	19,490	19,738	19,952	20,362	20,630	20,828	21,024	21,186	21,432	21,814	22,103
1b. Additional Forecast																			
NCEMC	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-47	-51	-69	-95	-127	-151	-170	-179	-177	-174	-174	-175	-176	-177	-178	-178	-180	-181	-182
3. Demand Response[2][5]	-83	-117	-82	-128	-134	-134	-135	-136	-137	-138	-139	-140	-141	-142	-143	-144	-145	-146	-147
4. Demand Response-Existing[2][3]	-5	-3	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
5. Peak Adjustment	-	-	-	-378	-666	-651	-745	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
6. Adjusted Load	16,469	16,348	16,461	17,147	17,207	17,578	17,835	18,891	19,257	19,509	19,724	20,132	20,399	20,597	20,792	20,953	21,197	21,579	21,866
7. % Increase in Adjusted Load	-2.5%	-0.7%	0.7%	4.2%	0.4%	2.2%	1.5%	5.9%	1.9%	1.3%	1.1%	2.1%	1.3%	1.0%	0.9%	0.8%	1.2%	1.8%	1.3%
(from previous year)																			
B. Winter																			
1a. Base Forecast	15,106	16,840	18,688	15,611	15,896	16,053	16,327	16,562	16,788	17,095	17,265	17,377	17,713	17,931	18,266	18,604	18,631	18,878	19,126
1b. Additional Forecast																			
NCEMC	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-47	-51	-69	-0.6	-3	-6	-10	-14	-15	-15	-15	-15	-15	-15	-16	-16	-16	-16	-16
3. Demand Response[2][4]	-15	-14	-5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4. Demand Response-Existing[2][3]	-5	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
5. Adjusted Load	15,209	16,939	18,619	15,611	15,894	16,046	16,317	16,548	16,774	17,080	17,250	17,362	17,698	17,916	18,250	18,588	18,615	18,862	19,110
6. % Increase in Adjusted Load	3.8%	11.4%	9.9%	-16.2%	1.8%	1.0%	1.7%	1.4%	1.4%	1.8%	1.0%	0.6%	1.9%	1.2%	1.9%	1.9%	0.1%	1.3%	1.3%
2. Energy (GWh)																			
A. Base Forecast	83,311	84,401	84,755	86,684	87,986	89,394	90,869	92,541	94,042	95,660	97,234	98,678	100,061	101,462	102,863	104,250	105,652	107,063	108,636
B. Additional Forecast																			
Future BTM[6]	-	-	-	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410
C. Conservation & Demand Response[5]	-351	-558	-464	-613	-757	-836	-862	-856	-784	-727	-720	-726	-729	-730	-733	-737	-741	-747	-752
D. Demand Response-Existing[2][3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	82,960	83,843	84,290	85,662	86,819	88,148	89,597	91,276	92,849	94,524	96,104	97,542	98,922	100,323	101,720	103,104	104,501	105,906	107,474
F. % Increase in Adjusted Energy	2.2%	1.1%	0.5%	1.6%	1.4%	1.5%	1.6%	1.9%	1.7%	1.8%	1.7%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.5%

(1) Actual metered data.

(2) Demand response programs are classified as capacity resources and are not included in adjusted load.

(3) Existing DSM programs are included in the load forecast.

(4) Actual historical data based upon measured and verified EM&V results.

(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

(6) Future BTM, which is not included in the Base forecast.

Appendix 2J – Required Reserve Margin for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	3,026	3,955	3,742	4,082	3,970	3,778	3,200	2,582	2,399	2,431	2,665	2,508	2,542	2,566	2,590	2,611	2,641	2,909	2,724
b. Percent of Load	18.4%	24.2%	22.7%	23.8%	23.1%	21.5%	17.9%	13.7%	12.5%	12.5%	13.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	13.5%	12.5%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	21.5%	13.4%	10.4%	15.7%	13.7%	12.0%	12.0%	13.5%	11.7%	10.8%	10.1%	9.4%	8.9%	7.9%	13.5%	12.2%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	5,304	6,010	4,956	6,419	5,889	5,708	5,706	6,060	5,991	5,697	5,520	5,213	4,903	4,896	6,357	6,123
b. Percent of Load	N/A	N/A	N/A	34.0%	37.8%	30.9%	39.3%	35.6%	34.0%	33.4%	35.1%	34.5%	32.2%	30.8%	28.6%	26.4%	26.3%	33.7%	32.0%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin[1][2]																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	3,026	3,955	3,742	4,082	3,970	3,778	3,200	2,582	2,399	2,431	2,665	2,508	2,542	2,566	2,590	2,611	2,641	2,909	2,724
b. Percent of Load	18.4%	24.2%	22.7%	23.8%	23.1%	21.5%	17.9%	13.7%	12.5%	12.5%	13.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	13.5%	12.5%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	21.5%	13.4%	10.4%	15.7%	13.7%	12.0%	12.0%	13.5%	11.7%	10.8%	10.1%	9.4%	8.9%	7.9%	13.5%	12.2%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	5,304	6,010	4,956	6,419	5,889	5,708	5,706	6,060	5,991	5,697	5,520	5,213	4,903	4,896	6,357	6,123
b. Percent of Load	N/A	N/A	N/A	34.0%	37.8%	30.9%	39.3%	35.6%	34.0%	33.4%	35.1%	34.5%	32.2%	30.8%	28.6%	26.4%	26.3%	33.7%	32.0%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.

(2) The Company and PJM forecast a summer peak throughout the Planning Period.

(3) Does not include spot purchases of capacity.

(4) The Company follows PJM reserve requirements which are based on LOLE.

Appendix 2K – Economic Assumptions used In the Sales and Hourly Budget Forecast Model
(Annual Growth Rate)

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	CAGR
Population: Total, (Ths.)	8,460	8,530	8,601	8,672	8,742	8,812	8,881	8,950	9,017	9,084	9,149	9,213	9,276	9,337	9,398	9,457	0.7%
Disposable Personal Income; (Mil. 09$; SAAR)	361,796	376,487	391,916	401,253	407,657	414,967	423,047	431,289	439,572	448,502	458,073	468,674	479,719	491,195	503,004	514,989	2.4%
Per Capita Disposable Personal Income; (C 09$; SAAR)	42.8	44.1	45.6	46.3	46.6	47.1	47.6	48.2	48.8	49.4	50.1	50.9	51.7	52.6	53.5	54.5	1.6%
Residential Permits: Total, (#, SAAR)	41,215	48,965	50,700	48,332	48,682	50,797	52,252	51,558	48,937	46,053	43,973	42,642	41,570	40,561	40,164	39,716	-0.2%
Employment: Total Manufacturing, (Ths., SA)	235	235	236	235	232	228	225	222	219	216	214	211	209	207	206	204	-0.9%
Employment: Total Government, (Ths., SA)	712.2	714.2	716.6	719.4	722.7	727.4	733.2	738.4	743.1	747.8	752.6	757.5	762.6	767.9	773.3	778.4	0.6%
Employment: Military personnel, (Ths., SA)	136	133	131	129	127	126	125	125	124	124	124	123	123	122	122	121	-0.7%
Employment: State and local government, (Ths., SA)	542	544	547	550	553	558	563	568	573	578	583	587	592	598	603	608	0.8%
Employment: Commercial Sector (Ths., SA)	2,728.3	2,798.2	2,866.8	2,914.0	2,933.4	2,948.4	2,969.9	2,994.0	3,015.7	3,038.3	3,061.7	3,084.8	3,108.8	3,134.6	3,161.4	3,188.7	1.0%
Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR)	40,619	41,758	42,620	43,283	43,699	44,198	44,781	45,372	45,928	46,499	47,123	47,808	48,535	49,275	50,007	50,733	1.5%
Gross State Product: Total; (Bil. Chained 2009 $; SAAR)	451.4	467.2	480.9	491.2	499.3	508.7	519.1	529.3	539.0	548.8	559.0	569.8	581.0	592.5	604.1	615.8	2.1%
Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR)	36,330	36,794	37,117	37,294	37,488	37,838	38,234	38,614	38,968	39,325	39,687	40,038	40,364	40,676	40,973	41,265	0.85%

Source: Economy.com December 2015 vintage

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	CAGR
Population: Total, (Ths.)	8,333	8,404	8,477	8,550	8,625	8,699	8,773	8,847	8,920	8,993	9,065	9,136	9,206	9,276	9,344	9,412	0.8%
Disposable Personal Income, (Mil. 05$, SAAR)	323,048	336,260	350,735	360,280	367,706	374,761	382,260	390,426	398,616	405,763	412,697	419,783	427,296	435,292	443,636	451,881	2.3%
per Capita Real Disposable Personal Income, (Ths.. 05$, SAAR)	38.8	40.0	41.4	42.1	42.6	43.1	43.6	44.1	44.7	45.1	45.5	46.0	46.4	46.9	47.5	48.0	1.4%
Residential Permits: Total, (#, SAAR)	40,802	61,742	62,477	54,947	46,620	42,002	40,352	38,837	38,199	36,835	35,968	36,015	36,310	35,828	34,566	34,203	-1.2%
Employment: Total Manufacturing, (Ths., SA)	230	231	234	234	233	231	229	227	224	222	220	217	215	213	212	210	-0.6%
Employment: Total Government, (Ths., SA)	708.8	711.9	711.9	711.7	712.2	712.9	713.7	715.4	717.0	718.2	718.9	719.6	719.9	720.0	720.4	721.2	0.1%
Employment: Military personnel, (Ths., SA)	146	144	141	138	135	133	130	128	127	126	125	125	124	123	122	121	-1.2%
Employment: State and local government, (Ths., SA)	541	548	549	550	550	551	552	553	555	556	557	558	558	559	559	560	0.2%
Employment: Commercial Sector (Ths., SA)	2,665.6	2,732.7	2,801.4	2,846.4	2,872.1	2,892.3	2,914.0	2,937.3	2,958.0	2,977.0	2,994.9	3,011.9	3,029.4	3,049.4	3,071.0	3,090.8	1.0%
Gross Product: Manufacturing, (Mil. Chained 2005 $, SAAR)	39,309	41,404	43,125	44,296	45,475	46,857	48,238	49,528	50,770	52,034	53,303	54,627	56,033	57,527	59,062	60,593	2.9%
Gross State Product: Total, (Bil. Chained 2005 $, SAAR)	407.2	423.4	434.7	443.6	451.4	458.3	465.9	474.7	483.7	492.4	500.8	509.1	517.5	526.2	535.3	544.3	2.0%
Gross Product: State & Local Government, (Mil. Chained 2005 $, SAAR)	27,893	27,839	27,526	27,301	27,140	27,033	27,011	27,044	27,057	27,021	26,949	26,828	26,659	26,474	26,294	26,108	-0.44%

Source: Economy.com March 2014 vintage

Appendix 2L – Alternative Residential Rate Design Analysis

The Company's Customer Rates group developed five alternative residential Schedule 1 rate designs to be used as model inputs to the Company's load forecasting models. Alternative residential Schedule 1 rate designs were intended to be revenue neutral on a rate design basis and were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models. The five rate designs are presented for analytical purposes only subject to the limitations discussed in more detail below. These studies should not be interpreted to be alternative rate design proposals by the Company for the revision of the Company's rates.

Alternative Residential Schedule 1 Rate Designs to the Company's Existing Base Rates[17]:

- Study A: Flat winter generation rates with inclining summer generation rates and no change to existing distribution rates;
- Study B: Increased differential between summer and winter rates for residential customers above the 800 kWh block (i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month). No changes to distribution rates;
- Study C: Schedule 1 residential rate with an alternative RAC design for the generation riders. No change in the existing summer generation rates or existing distribution rates;
- Study D: Flat winter generation rates with inclining summer generation rates with an alternative RAC design for the generation riders. No change to existing distribution rates;
- Study E: Increased differential between summer and winter rates for residential customers above the 800 kWh block, (i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month) with an alternative RAC design for the generation riders. No changes to distribution rates.

[17] Base months are also referred to as winter months and are essentially the non-summer months of October – May. Summer months extend from June – September.

Appendix 2L cont. – Alternative Residential Rate Design Analysis

Residential Rate Designs

				Alternative RAC	Alternative RAC	Alternative RAC
		Study A	Study B	Study C	Study D	Study E
Base Rates	Schedule 1 Rates (effective 1/1/2016)	Flat Winter Generation & Inclining Summer Generation Rate	Increased Differential Rate	Schedule 1 Rate	Flat Winter Generation & Inclining Summer Generation Rate	Increased Summer/Winter Differential Rate
DISTRIBUTION CHARGES						
Basic Customer Charge	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00
Energy - Summer						
First 800 kWh-Summer	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244
Add'l Peak kWh-Summer	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271
Energy - Winter (Base)						
First 800 kWh-Base	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244	$ 0.02244
Add'l Peak kWh-Base	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271	$ 0.01271
GENERATION CHARGES						
Energy - Summer						
First 800 kWH	$ 0.03795	$ 0.03417	$ 0.03795	$ 0.03795	$ 0.03417	$ 0.03795
Over 800 kWH	$ 0.05773	$ 0.06333	$ 0.06039	$ 0.05773	$ 0.06333	$ 0.06039
Energy - Winter (Base)						
First 800 kWH	$ 0.03795	$ 0.03417	$ 0.03795	$ 0.03795	$ 0.03417	$ 0.03795
Over 800 kWH	$ 0.02927	$ 0.03417	$ 0.02802	$ 0.02927	$ 0.03417	$ 0.02802
GENERATION RIDERS (RAC)						
A6 - RIDER - GEN RIDER B	$ 0.000150	$ 0.000150	$ 0.000150			
A6 - RIDER - GEN RIDER BW	$ 0.001600	$ 0.001600	$ 0.001600			
A6 - RIDER - GEN RIDER R	$ 0.001429	$ 0.001429	$ 0.001429			
A6 - RIDER - GEN RIDER S	$ 0.004180	$ 0.004180	$ 0.004180			
A6 - RIDER - GEN RIDER W	$ 0.002300	$ 0.002300	$ 0.002300			
SUBTOTAL GEN RIDERS:	**$ 0.009659**	**$ 0.009659**	**$ 0.009659**			
ALTERNATIVE RAC FOR GEN RIDERS				(Alternative RAC for GEN Riders)		
Energy - Summer						
First 800 kWH				$ 0.009387	$ 0.009387	$ 0.009387
Over 800 kWH				$ 0.011397	$ 0.011397	$ 0.011397
Energy - Winter (Base)						
First 800 kWH				$ 0.009387	$ 0.009387	$ 0.009387
Over 800 kWH				$ 0.009387	$ 0.009387	$ 0.009387
NON-GEN RIDERS						
A4 - Transmission	$ 0.01354	$ 0.01354	$ 0.01354	$ 0.01354	$ 0.01354	$ 0.01354
A5 - DSM	$ 0.00068	$ 0.00068	$ 0.00068	$ 0.00068	$ 0.00068	$ 0.00068
Fuel Rider A	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406
SUBTOTAL NON-GEN RIDERS:	**$ 0.03828**	**$ 0.03828**	**$ 0.03828**	**$ 0.03828**	**$ 0.03828**	**$ 0.03828**

Appendix 2L cont. – Alternative Residential Rate Design Analysis

Study Method

The Company's current sales forecast model uses the real (inflation adjusted) price of residential electricity as one input to forecast the level of electricity consumed or demanded. This modeling construct allows the inverse nature of price and quantity to be recognized such that changes in price have the opposite effects on quantity (i.e., law of demand). The price inputs and quantity outputs can then be used to determine the elasticity of demand for electricity or the percent change in quantity divided by the percent change in price.

The residential price variable is an input for both the sales and peak models. Both models utilize a short-term, 12-month moving average, and long-term 5-year moving average price variable. The short-term price is interacted with disposable income and appliance stock to reflect residential consumption changes that may occur as a result of transitional price changes such as fuel or rider rates. The long-term price changes are interacted with weather sensitive residential electricity consumption (heat and cooling stock of appliances) such that long-term durable goods (i.e., heat pumps and air conditioning) will adjust to reflect both appliance alternatives and efficiency improvements in weather sensitive appliance stocks.

The primary method used to test the alternative rates is through price or elasticity measures. Price elasticity of demand commonly refers to a change in the quantity demanded given a change in price. The main challenge in developing price responsive models is that all customers have specific demand curves (usage levels and sensitivities to prices among other variables), and it is not feasible to develop individual demand response functions for all customers that the Company serves. Generally, the average reaction to a price change is used to estimate price sensitivity of the Company's customers and hence determines the new quantity of forecasted electricity needed. This method is generally designed for incremental analysis which contemplates only marginal changes in prices. Large changes to pricing structures can have impacts outside of the model's abilities to predict quantity changes (i.e., behavioral changes related to budget, income, or substitution). Therefore, the alternative study results should be interpreted with these limitations in mind.

The modeling methods employed by the Company attempt to isolate the change in quantity-related demand and sales as a result of the alternative pricing structures. Additional observations about the rate and consumption outcomes are provided below (i.e., rate change impacts on particular bill levels). Changes to the load shape (seasonal peak and energy) and levels of consumption were analyzed in the Strategist model to estimate operational cost differences.

The rate comparison graphs discussed below are static in nature and were developed using annual summer and winter average rates and are for modeling purposes only. All rate changes were implemented immediately in the Company's load forecasting models and are dynamic in nature (2016 rates) so the Company's models could absorb the rate changes over the approximately 5-year window used to model electricity price changes as they relate to peak demand and sales levels. Thus, the analysis is expected to normalize by approximately 2021. All comparisons are made to the base set of assumptions as identified in Figure 2L.1.

Appendix 2L cont. – Alternative Residential Rate Design Analysis

Residential Rate Design Analysis Results

The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities is approximately -0.06, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.06%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure on sales and peak levels. However, the impact of lower summer rates is larger summer peaks which would likely require more capacity or market purchases to maintain reliability. Price changes are not expected to be uniform across the year because of the weighted average effect of seasonal usage levels and the different period of summer (4 months) and non-summer (8 months) seasonal rates.

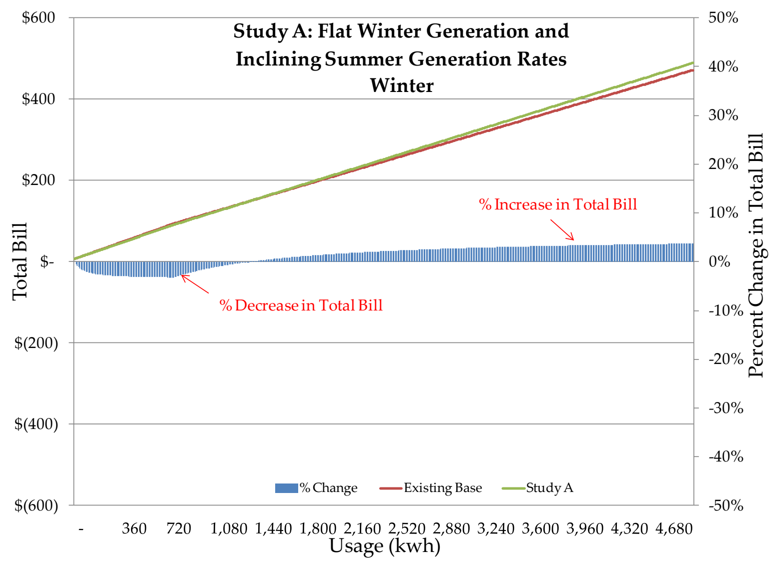
1% increase in the average residential price of electricity would reduce average consumption by approximately 0.06%.

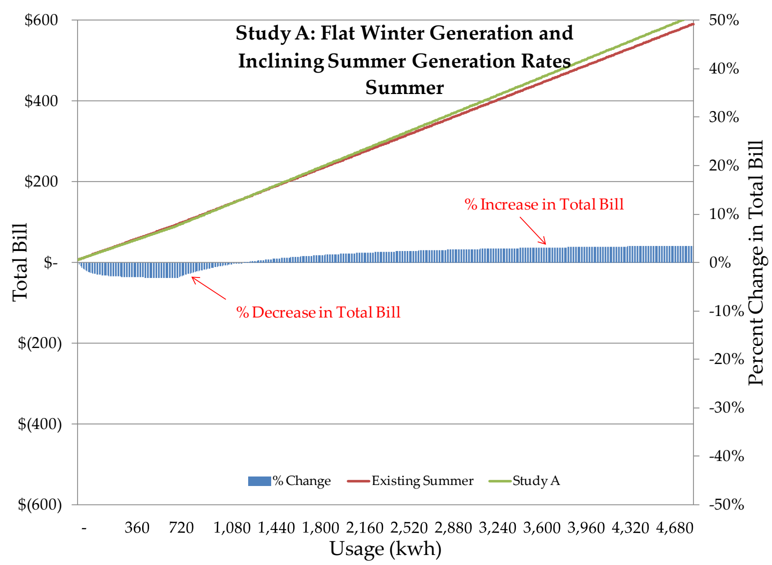
The rate studies below estimate the impact on the total bill during the summer and winter (non-summer) periods. Summer months include June through September. Winter (or non-summer, or base) months extend from October through May. The pricing inputs are translated into total bill amounts below to show an instantaneous base rate change that occurs in 2016 relative to the base portion of customers' bills for up to 5,000 kWh of usage. The upward sloping lines represent the total bill under the existing and alternative rate and are measured along the left axis. The shaded area represents the percent change in total bill from the existing to alternative rate and is measured along the right axis. Below each seasonal rate impact slide are charts that reflect the associated change in seasonal peak from 2016 through 2031 that results from the total change in annual rates over time. Finally, the change in annual sales is presented to reflect the appropriate weighted average of each rate study.

Appendix 2L.1 – Alternative Residential Rate Design Analysis – Flat Winter Generation and Inclining Summer Generation

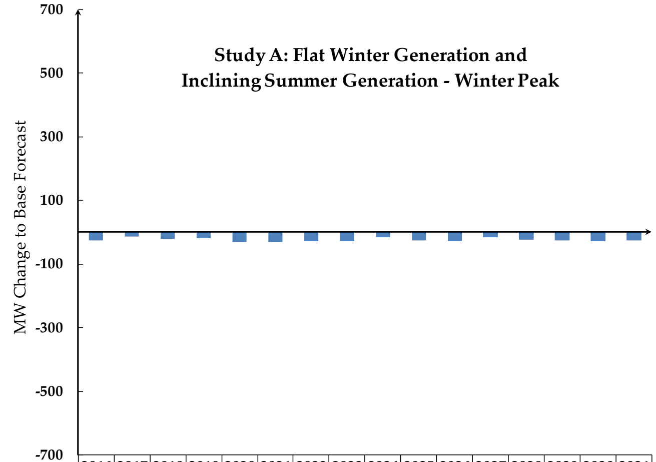
Study A: Flat Winter Generation and Inclining Summer Generation

Flat winter generation and inclining summer generation results in a small decrease in the total bill of low usage customers (<800 kWh) in both the winter and summer; however, higher usage customers experience slight total bill increases in the winter and summer. Winter peak decreases slightly and summer peak is reduced as well. Total annual sales are negatively impacted by the summer rate increase for customers using more than 800 kWh per month along with the increase in winter rates which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units.

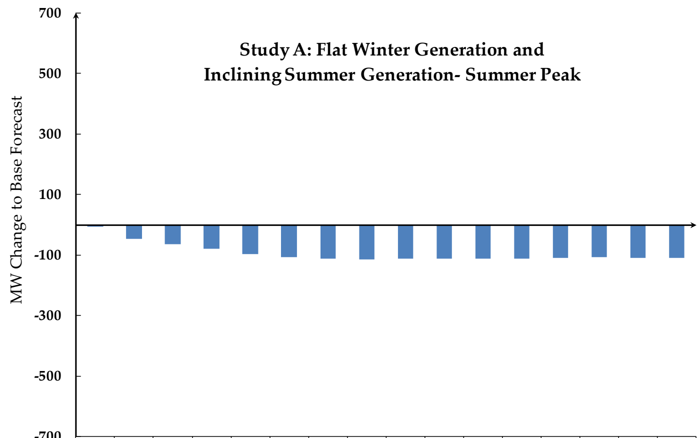




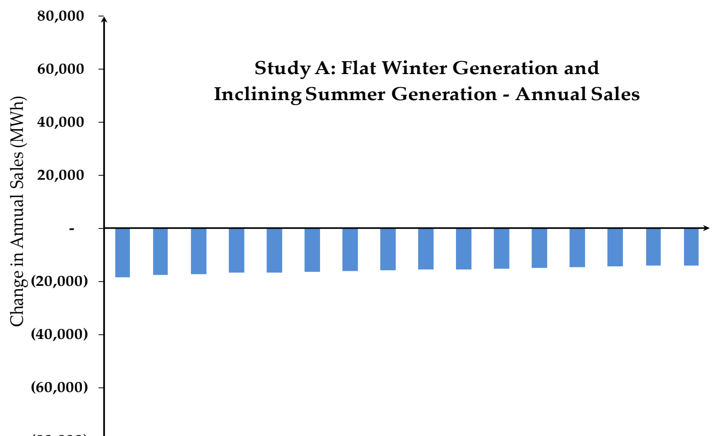
Appendix 2L.1 cont. – Alternative Residential Rate Design Analysis – Flat Winter Generation and Inclining Summer Generation



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	-26	-14	-20	-19	-32	-30	-27	-28	-16	-26	-28	-16	-25	-25	-27	-27



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	-7	-48	-64	-80	-96	-107	-113	-114	-111	-113	-113	-111	-110	-107	-109	-110

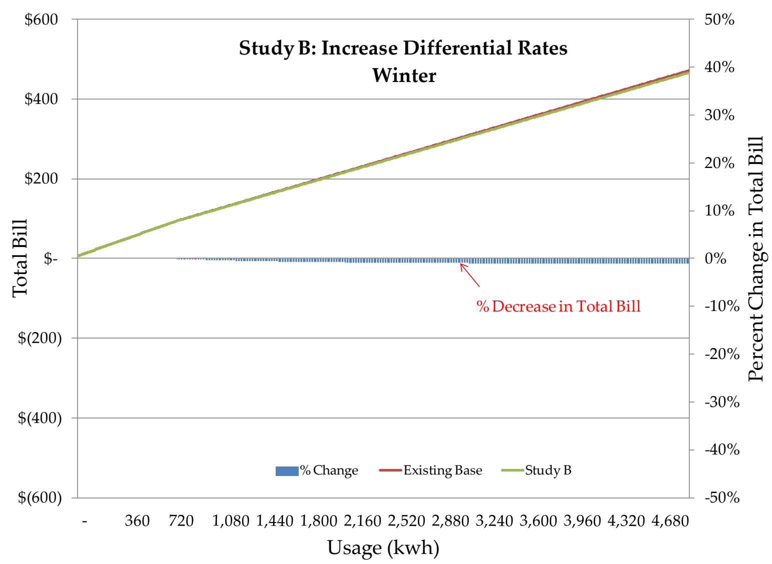


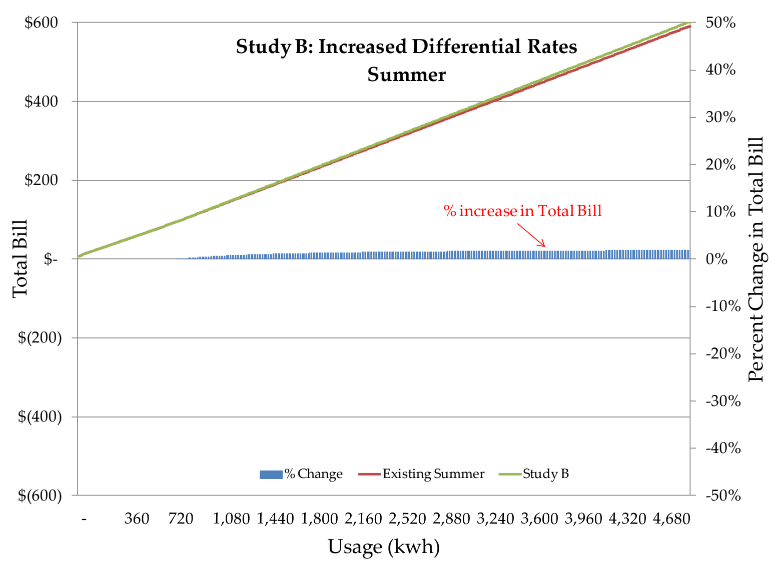
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	(18,376)	(17,684)	(17,172)	(16,762)	(16,556)	(16,358)	(16,114)	(15,880)	(15,629)	(15,378)	(15,123)	(14,862)	(14,583)	(14,283)	(13,971)	(13,961)

Appendix 2L.2 – Alternative Residential Rate Design Analysis – Summer/Winter Differential Increased

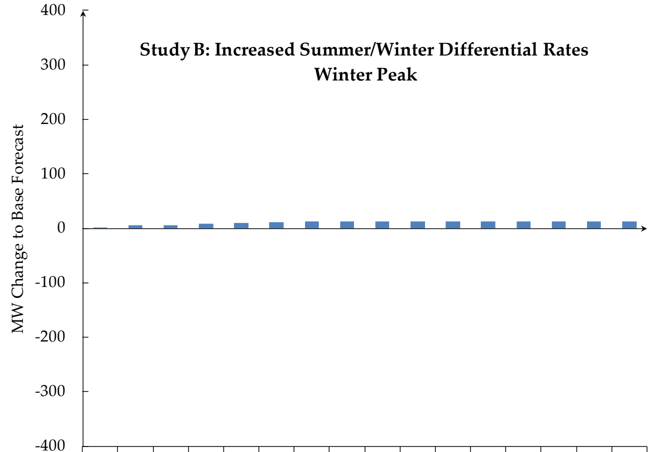
Study B: Summer/Winter Differential Increased

Increasing the summer/winter rate differential (summer increase/winter decrease) primarily impacts users above 800 kWh. Higher usage customers experience slight total bill decreases in the winter and slight total bill increases in the summer. Customers at or below 800 kWh of usage see no change in total bills. Winter peak slightly increases and summer peak is reduced. Total annual sales slightly decrease due to the decrease in winter rates partially offset by the summer rate increase.

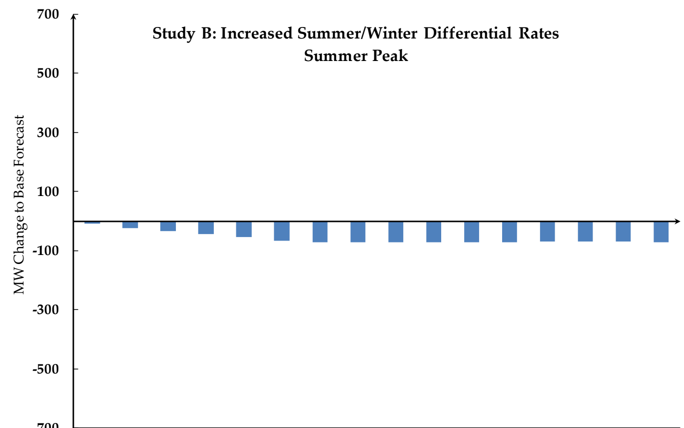




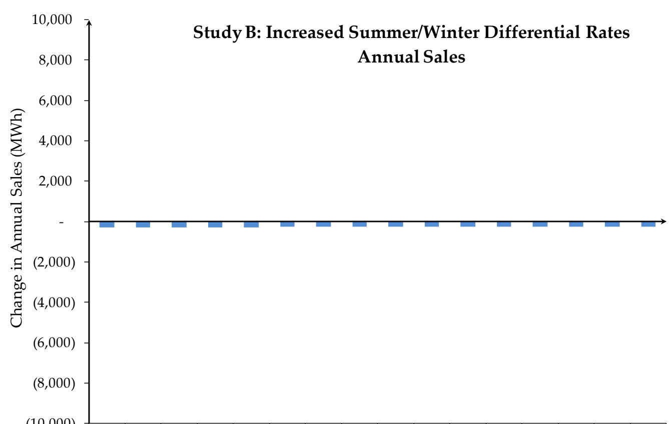
Appendix 2L.2 cont. – Alternative Residential Rate Design Analysis – Summer/Winter Differential Increased



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	2	5	6	8	10	11	13	13	13	12	12	12	12	12	12	12



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	-9	-24	-34	-44	-55	-66	-72	-72	-71	-72	-72	-71	-70	-69	-69	-70

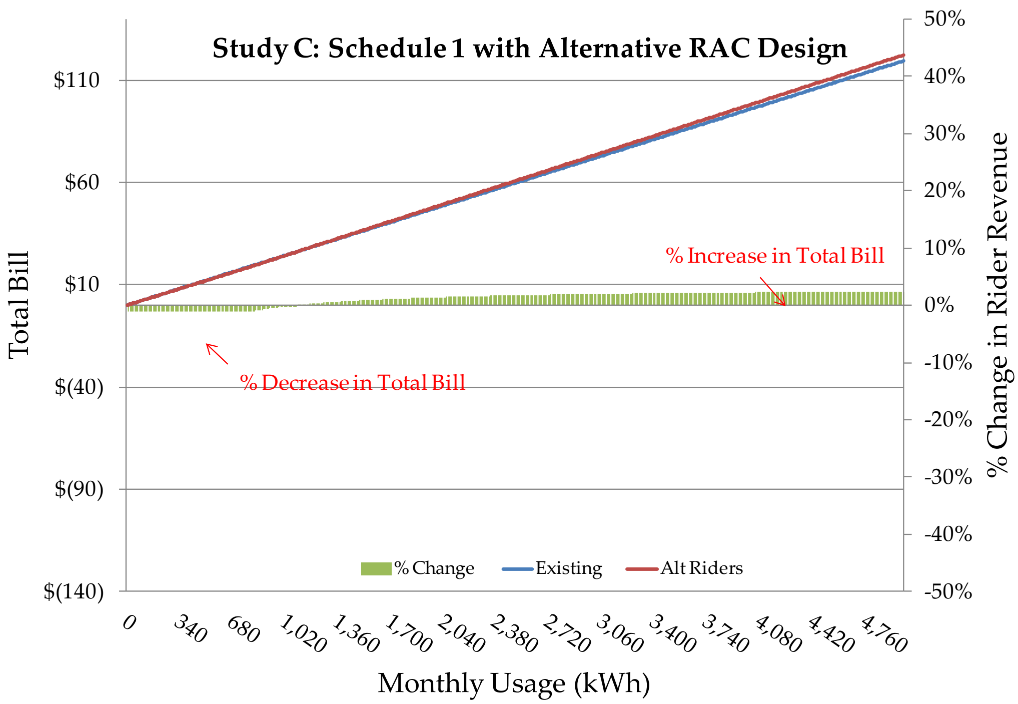


	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	(302)	(279)	(271)	(273)	(268)	(257)	(246)	(249)	(248)	(243)	(241)	(235)	(239)	(236)	(232)	(230)

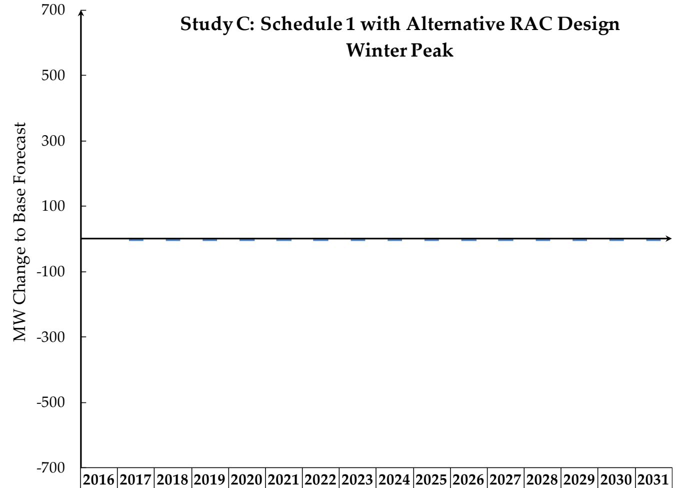
Appendix 2L.3 – Alternative Residential Rate Design Analysis – Schedule 1

Study C: Schedule 1 (Alternative RAC Design)

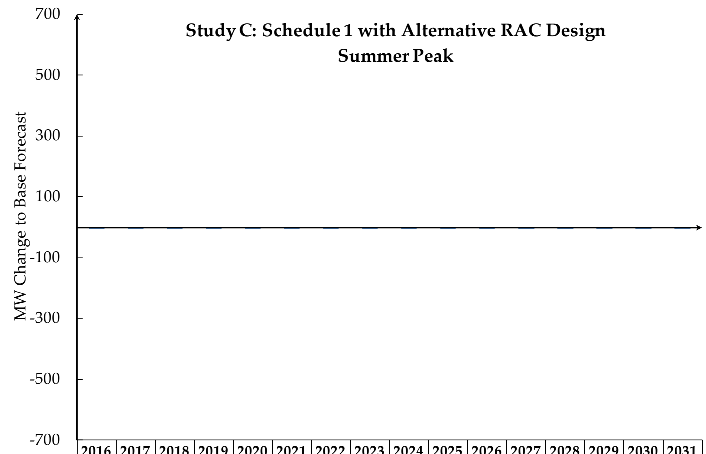
This study evaluates the impact of an alternative RAC rate design for Schedule 1 customers. In previous alternative residential rate design studies, the RAC rates were held constant. In this analysis, the RAC design varies with energy usage. The analysis results in a small decrease in the total bill of low usage customers (<800 kWh); however, higher usage customers experience total bill increases. Winter and summer peak are unaffected by this change. Total annual sales are negatively impacted due to the reduction in sales, which is attributed to customers using less energy as their usage cost increases. This, in turn, could result in higher base rates due to costs being recovered over fewer sales units.



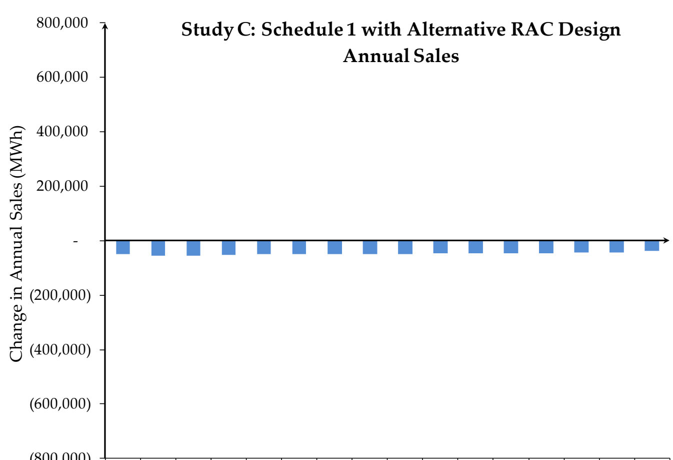
Appendix 2L.3 cont. – Alternative Residential Rate Design Analysis – Schedule 1



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	0	-7	-6	-6	-6	-6	-6	-6	-6	-6	-6	-5	-5	-5	-5	-5



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	-6	-7	-7	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-5	-5	-5

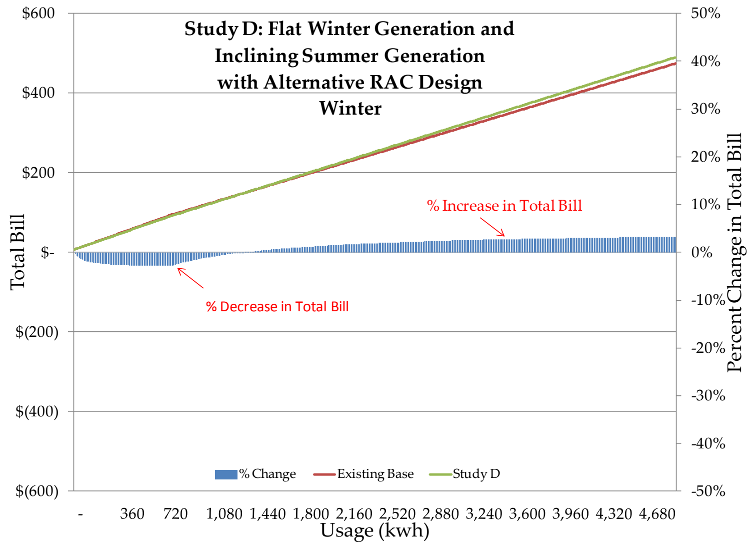


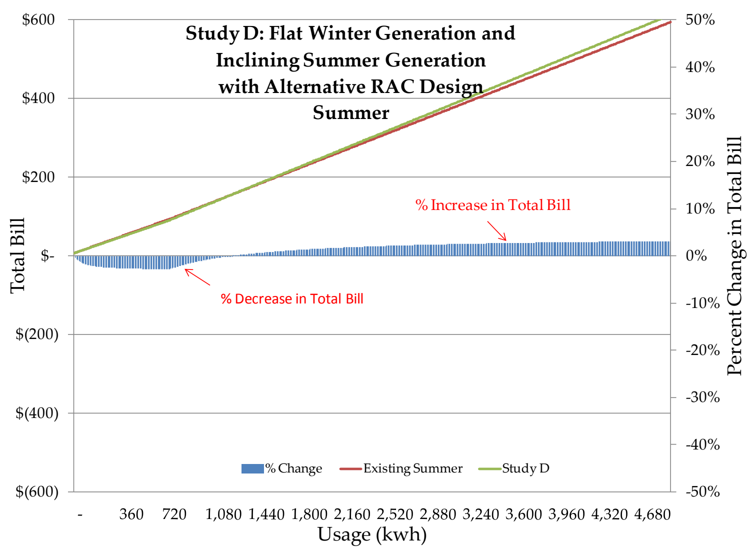
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	(48,132)	(56,390)	(54,063)	(51,944)	(50,908)	(50,424)	(49,877)	(49,275)	(48,660)	(48,022)	(47,297)	(46,489)	(45,577)	(44,628)	(43,580)	(37,563)

Appendix 2L.4 – Alternative Residential Rate Design Analysis – Flat Winter Generation and Inclining Summer Generation

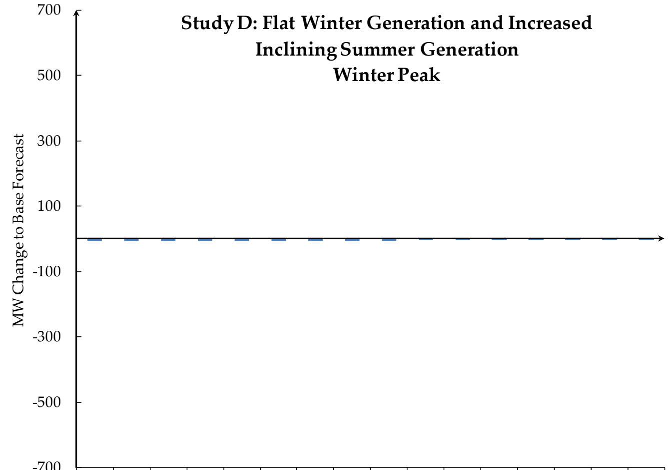
Study D: Flat Winter Generation and Inclining Summer Generation (Alternative RAC Design)

While similar to Study A, this analysis will assume flat winter generation and increasing summer generation is the baseline and the RAC rate design will change to vary with energy usage. In previous alternative residential rate design studies, the RAC rates were held constant. The analysis results in a small decrease in the total bill of low usage customers (<800 kWh) in both the winter and summer; however, higher usage customers experience slight total bill increases in the winter and summer. Winter and summer peak are unaffected by this change. Total annual sales are negatively impacted due to the reduction in sales, which is attributed to customers using less energy as their usage cost increases. This, in turn, could result in higher base rates due to costs being recovered over fewer sales units.

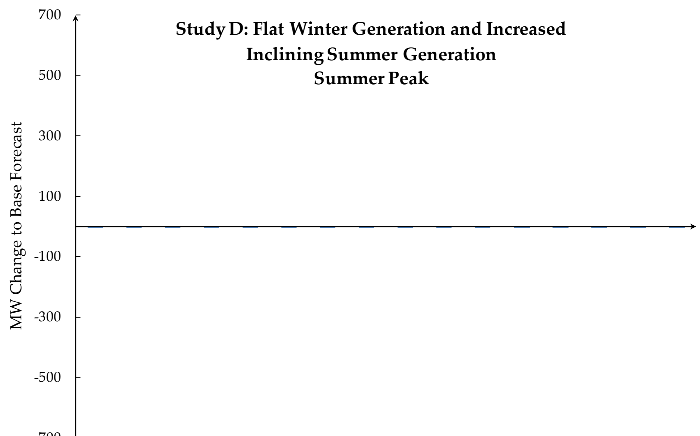




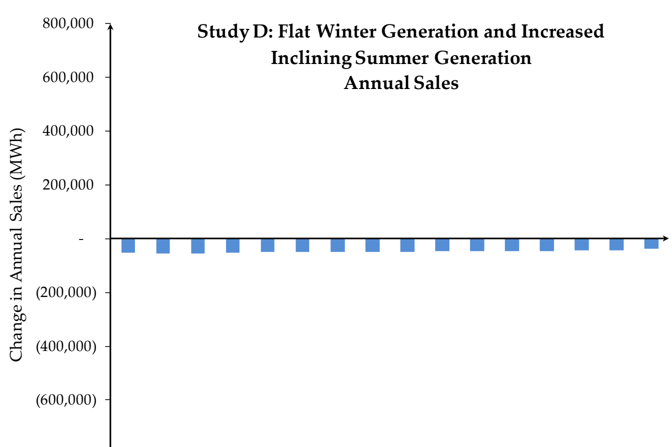
Appendix 2L.4 cont. – Alternative Residential Rate Design Analysis – Flat Winter Generation and Inclining Summer Generation



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	-6	-6	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-4	-5



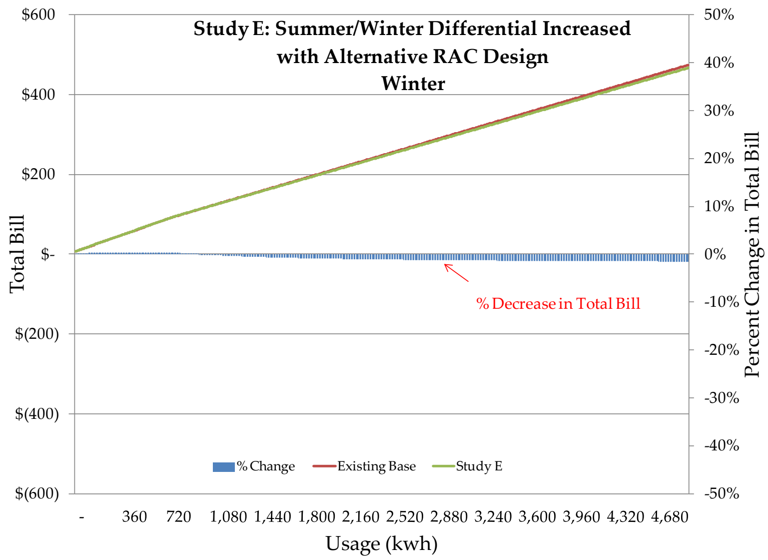
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	-6	-6	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5

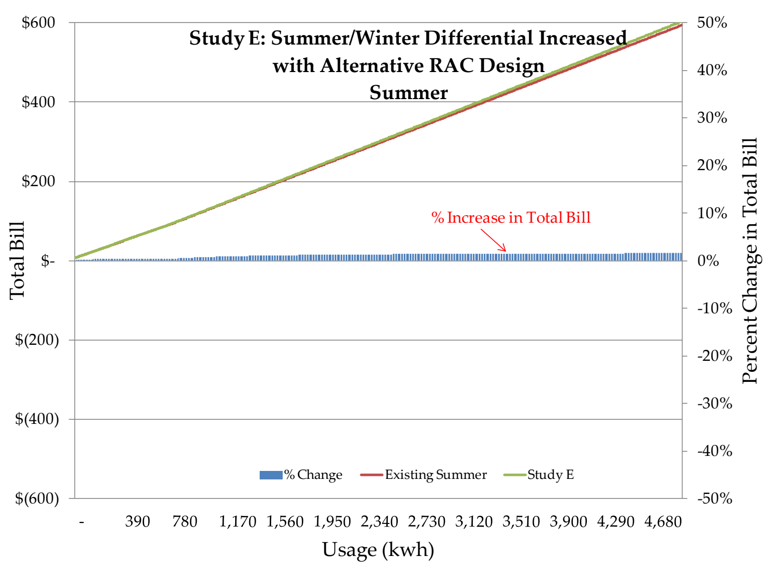


	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	(52,810)	(56,390)	(54,063)	(51,944)	(50,908)	(50,424)	(49,877)	(49,275)	(48,660)	(48,022)	(47,297)	(46,489)	(45,577)	(44,628)	(43,580)	(37,564)

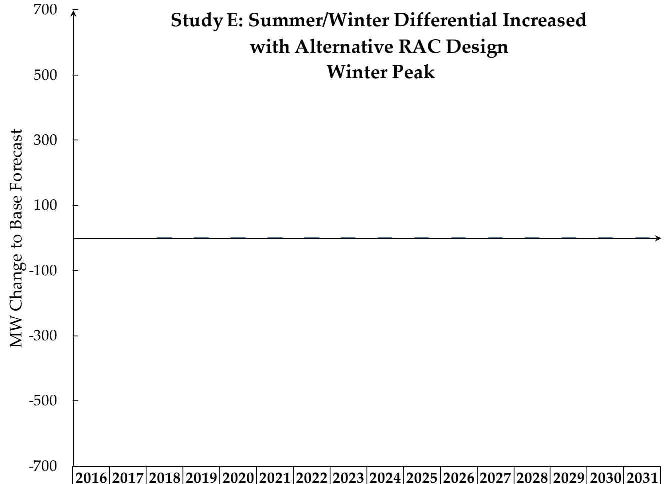
Appendix 2L.5 – Alternative Residential Rate Design Analysis – Summer/Winter Differential Increased

Study E: Summer/Winter Differential Increased (Alternative RAC Design)
While similar to Study B, this analysis will assume Summer/Winter Differential Increased is the baseline and the RAC rate design will change to vary with energy usage. In previous alternative residential rate design studies, the RAC rates were held constant. The analysis results in no change to the total bill of low usage customers (<800 kWh) in both the winter and summer; however, higher usage customers experience a slight decrease in their total bill during the winter and a slight increase during the summer. Winter and summer peak are unaffected by this change. Total annual sales are slightly decreased by this change.

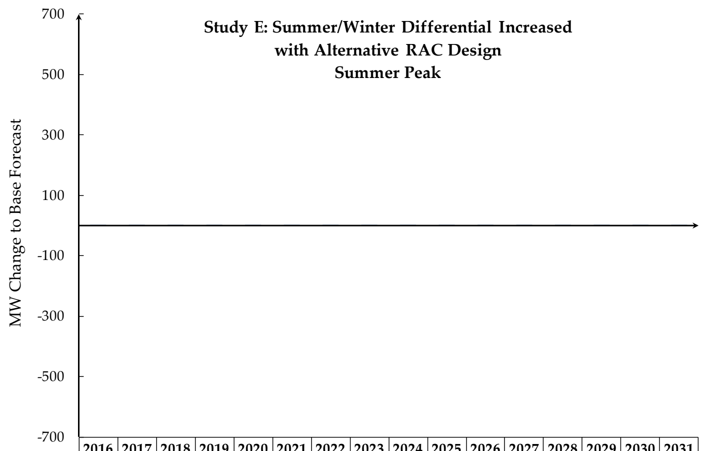




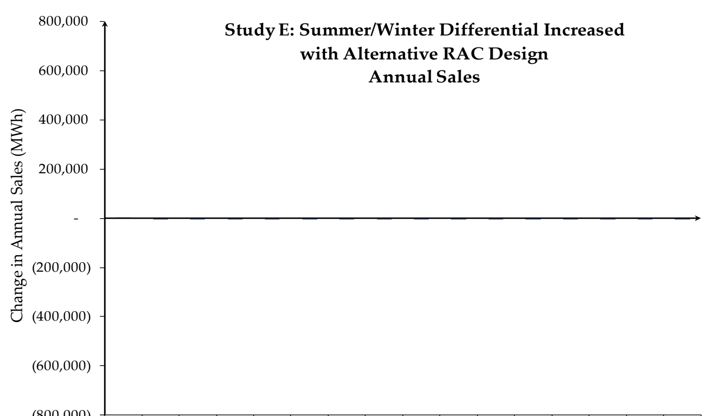
Appendix 2L.5 cont. – Alternative Residential Rate Design Analysis – Summer/Winter Differential Increased



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	720	(4,991)	(4,808)	(4,739)	(4,747)	(4,799)	(4,840)	(4,875)	(4,907)	(4,934)	(4,949)	(4,954)	(4,947)	(4,935)	(4,909)	(4,900)

Appendix 2M – Non-Residential Rate Analysis – Schedule GS-1

Alternative Non-Residential Schedule GS-1 Rate Design

The Company's Customer Rates group developed six alternative non-residential GS-1 and Schedule 10 rate designs to be used as model inputs to the Company's load forecasting models. Alternative Non-Residential GS-1 and Schedule 10 rate designs were intended to be revenue neutral on a rate design basis and were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models. The six rate designs are presented for analytical purposes only subject to the limitations discussed in more detail below. These studies should not be interpreted to be alternative rate design proposals by the Company for the revision of the Company's rates.

Alternative Non-Residential GS-1 Rate Designs to the Company's Existing Base Rates[18]:

- Study A: Flat rates during summer and winter for both distribution and generation;
- Study B: Inclining block rates during summer and winter with flat distribution rates;
- Study C: Flat winter generation rates with no change in the existing summer generation rates or existing distribution rates;
- Study D: Increased differential between summer and winter rates for commercial customers above the 1,400 kWh block, i.e., an increase in summer rates and a decrease in winter rates for commercial customers using more than 1,400 kWh per month with no changes to distribution rates; and
- Study E: Flat winter generation rate and increased inclining summer generation rate.

Alternative Non-Residential Rate Design for Schedule 10:

- Study F: Increase the on-peak rate for "A" days during the peak and off-peak seasons with no change to the off-peak rate. Reduce the peak and off-peak rates for "B" and "C" days for both the peak and off-peak seasons.

[18] Base months are also referred to as winter months and are essentially the non-summer months of October – May. Summer months extend from June – September.

Appendix 2M cont. – Non-Residential Rate Analysis

Non-Residential GS-1 Rate Designs

Schedule GS-1	Existing Rates (effective 1/1/2016)	GS-1 Alternative Rates Study A Flat Rate	Study B Year Round Inclining Block Rate	Study C Flat Winter Rate	Study D Increased Differential	Study E Flat Base Generation & Inclining Summer Generation Rate
DISTRIBUTION CHARGES						
Basic Customer Charge						
Single-Phase	$ 11.47	$ 11.47	$ 11.47	$ 11.47	$ 11.47	$ 11.47
Three-Phase	$ 15.47	$ 15.47	$ 15.47	$ 15.47	$ 15.47	$ 15.47
Unmetered	$ 9.47	$ 9.47	$ 9.47	$ 9.47	$ 9.47	$ 9.47
All Excess kW Demand	$ 1.48	$ 1.48	$ 1.48	$ 1.48	$ 1.48	$ 1.48
Minimum Demand	$ 3.13	$ 3.13	$ 3.13	$ 3.13	$ 3.13	$ 3.13
Energy[1]						
First 1400 kWh-Summer	$ 0.01814	$ 0.01448	$ 0.01448	$ 0.01814	$ 0.01448	$ 0.01448
Add'l Peak kWh-Summer	$ 0.01091	$ 0.01448	$ 0.01448	$ 0.01091	$ 0.01448	$ 0.01448
Base[2] **Months**						
First 1400 kWh-Base	$ 0.01814	$ 0.01448	$ 0.01448	$ 0.01814	$ 0.01448	$ 0.01448
Add'l Peak kWh-Base	$ 0.01091	$ 0.01448	$ 0.01448	$ 0.01091	$ 0.01448	$ 0.01448
GENERATION CHARGES						
Energy[1]						
First 1400 kWh-Summer	$ 0.03722	$ 0.03531	$ 0.02886	$ 0.03722	$ 0.03722	$ 0.03067
Add'l Peak kWh-Summer	$ 0.04995	$ 0.03531	$ 0.04159	$ 0.04995	$ 0.05536	$ 0.05582
Base[2] **Months**						
First 1400 kWh-Base	$ 0.03722	$ 0.03531	$ 0.02886	$ 0.03067	$ 0.03722	$ 0.03067
Add'l Peak kWh-Base	$ 0.02400	$ 0.03531	$ 0.04159	$ 0.03067	$ 0.02090	$ 0.03067
RIDERS (RAC)[3]						
A4 - Transmission	$ 0.00887	$ 0.00887	$ 0.00887	$ 0.00887	$ 0.00887	$ 0.00887
A5 - DSM	$ 0.00060	$ 0.00060	$ 0.00060	$ 0.00060	$ 0.00060	$ 0.00060
A6 - Rider - Gen Rider B	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013	$ 0.00013
A6 - Rider - Gen Rider BW	$ 0.00140	$ 0.00140	$ 0.00140	$ 0.00140	$ 0.00140	$ 0.00140
A6 - Rider - Gen Rider R	$ 0.00126	$ 0.00126	$ 0.00126	$ 0.00126	$ 0.00126	$ 0.00126
A6 - Rider - Gen Rider S	$ 0.00368	$ 0.00368	$ 0.00368	$ 0.00368	$ 0.00368	$ 0.00368
A6 - Rider - Gen Rider W	$ 0.00203	$ 0.00203	$ 0.00203	$ 0.00203	$ 0.00203	$ 0.00203
Fuel Rider A	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406	$ 0.02406
Total Riders per kWh	$ 0.04203	$ 0.04203	$ 0.04203	$ 0.04203	$ 0.04203	$ 0.04203

Note: 1) Energy block rates include Distribution and Generation charges.
2) Base months are the non-summer months of October – May.
3) No change to Riders.

Appendix 2M cont. – Non-Residential Rate Analysis

Non-Residential Schedule 10 Rate Designs

		Current Schedule 10 Rate Design				Alternative Schedule 10 Rate Design		
		"A" Days	"B" Days	"C" Days		"A" Days	"B" Days	"C" Days
Schedule 10 Rate Effective 1/1/2016	Day Type	30 Days	55 Days	280 Days	Day Type	30 Days	55 Days	280 Days
				DISTRIBUTION CHARGES				
Basic Customer Charge		$ 131.00	$ 131.00	$ 131.00		$ 131.00	$ 131.00	$ 131.00
Energy Charge (per kWh)								
Primary Voltage (all kWh)		$ 0.00006	$ 0.00006	$ 0.00006		$ 0.00006	$ 0.00006	$ 0.00006
Secondary Voltage (all kWh)		$ 0.00007	$ 0.00007	$ 0.00007		$ 0.00007	$ 0.00007	$ 0.00007
Demand Charge (per kW)								
Primary Voltage (first 5,000 kW)		$ 1.0000	$ 1.0000	$ 1.0000		$ 1.0000	$ 1.0000	$ 1.0000
Primary Voltage (additional kW)		$ 0.7550	$ 0.7550	$ 0.7550		$ 0.7550	$ 0.7550	$ 0.7550
Secondary Voltage (all kW)		$ 2.1200	$ 3.1200	$ 4.1200		$ 2.1200	$ 3.1200	$ 4.1200
				ELECTRICITY SUPPLY SERVICE CHARGES				
Electricity Supply - Demand Charge (per kW)		$ (0.07800)	$ (0.07800)	$ (0.07800)		$ (0.07800)	$ (0.07800)	$ (0.07800)
Generation Adjustment Demand Charge (per kW)								
Primary Voltage (first 5,000 kW)		$ (0.42100)	$ (0.42100)	$ (0.42100)		$ (0.42100)	$ (0.42100)	$ (0.42100)
Primary Voltage (additional kW)		$ (0.31800)	$ (0.31800)	$ (0.31800)		$ (0.31800)	$ (0.31800)	$ (0.31800)
Secondary Voltage (all kW)		$ (0.64000)	$ (0.64000)	$ (0.64000)		$ (0.64000)	$ (0.64000)	$ (0.64000)
				GENERATION CHARGES				
PEAK SEASON (per kWh)			**May 1 - September 30**				**May 1 - September 30**	
On-Peak (11 am - 9 pm)	A	$ 0.25678			A	$ 0.44331		
Off-Peak (9 pm - 11 am)	A	$ 0.02859			A	$ 0.02859		
On-Peak (11 am - 9 pm)	B		$ 0.02190		B		$ 0.01310	
Off-Peak (9 pm - 11 am)	B		$ 0.01425		B		$ 0.00852	
On-Peak (7 am - 10 pm)	C			$ 0.01425	C			$ 0.00852
Off-Peak (10 pm - 7 am)	C			$ 0.00974	C			$ 0.00582
OFF-PEAK SEASON (per kWh)			**October 1 - April 30**				**October 1 - April 30**	
On-Peak (6 am - Noon)	A	$ 0.25678			A	$ 0.44331		
Off-Peak (Noon - 5 pm)	A	$ 0.03308			A	$ 0.03308		
On-Peak (5 pm - 9 pm)	A	$ 0.25678			A	$ 0.44331		
On-Peak (6 am - Noon)	B		$ 0.21900		B		$ 0.01310	
Off-Peak (Noon - 5 pm)	B		$ 0.01528		B		$ 0.00914	
On-Peak (5 pm - 9 pm)	B		$ 0.21900		B		$ 0.01310	
On-Peak (6 am - Noon)	C			$ 0.01528	C			$ 0.00914
Off-Peak (Noon - 5 pm)	C			$ 0.01191	C			$ 0.00712
On-Peak (5 pm - 9 pm)	C			$ 0.01528	C			$ 0.00914
				GENERATION RIDERS (RAC)				
A6 - Rider - Gen Rider B		$ 0.000130	$ 0.000130	$ 0.000130		$ 0.000130	$ 0.000130	$ 0.000130
A6 - Rider - Gen Rider BW		$ 0.001400	$ 0.001400	$ 0.001400		$ 0.001400	$ 0.001400	$ 0.001400
A6 - Rider - Gen Rider R		$ 0.001257	$ 0.001257	$ 0.001257		$ 0.001257	$ 0.001257	$ 0.001257
A6 - Rider - Gen Rider S		$ 0.003680	$ 0.003680	$ 0.003680		$ 0.003680	$ 0.003680	$ 0.003680
A6 - Rider - Gen Rider W		$ 0.002030	$ 0.002030	$ 0.002030		$ 0.002030	$ 0.002030	$ 0.002030
SUBTOTAL GEN RIDERS:		**$ 0.008497**	**$ 0.008497**	**$ 0.008497**		**$ 0.008497**	**$ 0.008497**	**$ 0.008497**
				NON-GEN RIDERS				
A4 - Transmission		$ 0.008871	$ 0.008871	$ 0.008871		$ 0.008871	$ 0.008871	$ 0.008871
A5 - DSM		$ 0.000600	$ 0.000600	$ 0.000600		$ 0.000600	$ 0.000600	$ 0.000600
Fuel Rider A		$ 0.024060	$ 0.024060	$ 0.024060		$ 0.024060	$ 0.024060	$ 0.024060
SUBTOTAL NON-GEN RIDERS:		**$ 0.03353**	**$ 0.03353**	**$ 0.03353**		**$ 0.03353**	**$ 0.03353**	**$ 0.03353**

Appendix 2M cont. – Non-Residential Rate Analysis

Company Forecast Model

The Company's forecast model does not distinguish between individual non-residential rates. Rather, the Company's forecast model aggregates the sales of all non-residential rates and develops an average rate. Therefore, performing sensitivity analysis on a very small segment of total non-residential sales would only have a minimal effect on the Company's load forecast. For example, GS-1 tariff rate customers accounted for 9.8% of all non-residential jurisdictional sales during 2015 and 5.4% of total billed Virginia jurisdictional retail sales. Schedule 10 tariff rate customers accounted for 5.9% of all non-residential jurisdictional sales during 2015 and 3.3% of total billed Virginia jurisdictional retail sales.

Study Method

To adjust to the Company's forecast model and the limitations noted above, this study will develop an econometric model for the GS-1 and Schedule 10 sales and demonstrate the effect that the changed in rate design has on the system. The GS-1 and Schedule 10 models assume there will be no lag effect in customers' response to the higher rates.

Appendix 2M cont. – Non-Residential Rate Analysis

Non-Residential Rate Analysis Results

1% increase in the average price of electricity for GS-1 customers would reduce average consumption by approximately 0.4%.

1% increase in the average price of electricity on peak "A" days for GS-3 and GS-4 customers on Schedule 10 rates would reduce average consumption by approximately 0.11%.

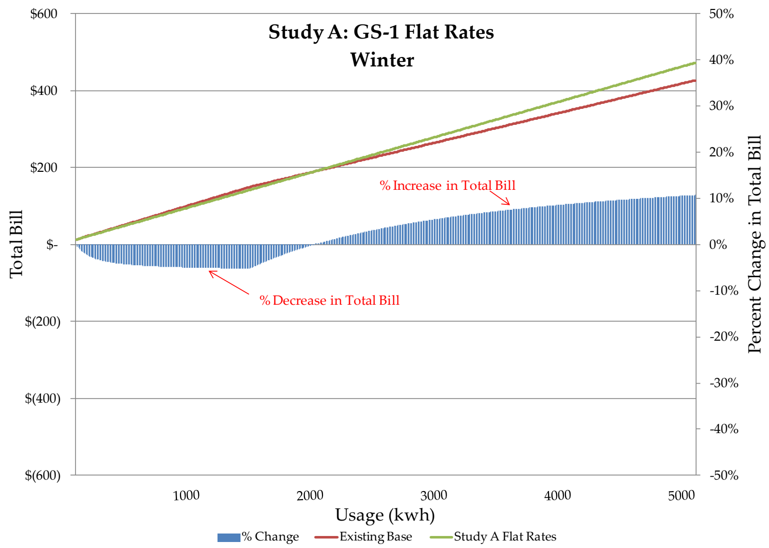
Like the residential class, the modeling results follow expectations such that increases in price lead to lower demand, and decreases in price lead to higher demand. The average calculation of elasticity over the modeled sensitivities for GS-1 rates is approximately -0.4, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.4%. Likewise, the average calculation of elasticity over the modeled sensitivities for GS-3 and GS-4 customers on Schedule 10 rates is approximately -0.11, meaning a 1% increase in the average price of electricity on peak "A" days would reduce average consumption by approximately 0.11%. The elasticity suggests that both GS-1 customers and GS-3 and GS-4 customers on Schedule 10 rates are more sensitive to price changes than the residential class and that increases in price, holding all other variables constant, will place downward pressure on sales and peak levels. Such an impact from recognition of a price elasticity effect on the generation and resource plan should also be recognized in the design of electricity rates. Lower summer rates, as produced in the some of the studies, results in higher summer peaks which would likely require more capacity or market purchases to maintain reliability. Price changes are not expected to be uniform across the year because of the weighted average effect of seasonal usage levels and the different period of summer (4 months) and winter (8 months) seasonal rates.

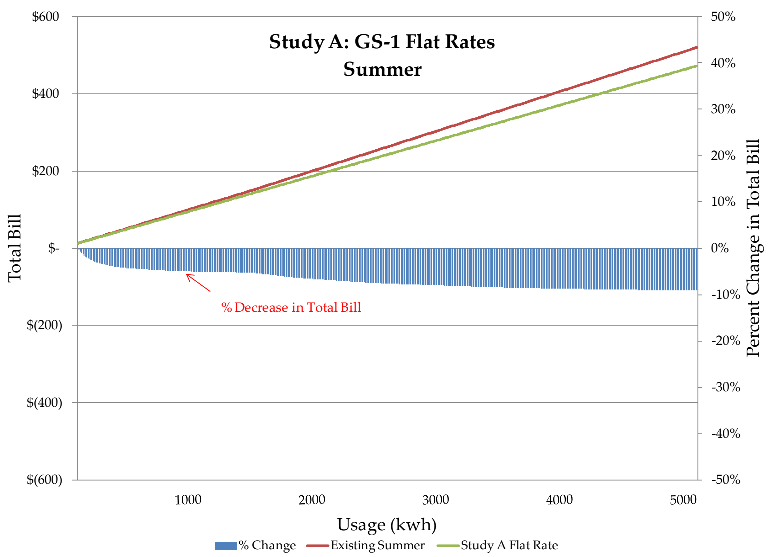
The rate studies shown below for the alternative GS-1 rates estimate the impact on the total bill during the summer and winter (or base) periods. The pricing inputs are translated into total bill amounts to show an instantaneous base rate change that occurs in 2016 relative to the base portion of the customer bill for up to 5,000 kWh of usage. The upward sloping lines represent the total bill under the existing and alternative rate and are measured along the left axis. The shaded area represents the percent change in total bill from the existing to alternative rate and is measured along the right axis. Below each seasonal rate impact slide are charts that reflect the associated change in seasonal peak from 2016 through 2031 that results from the total change in annual rates over time. Finally, the change in annual sales is presented to reflect the appropriate weighted average of each rate study.

Appendix 2M.1 – Non-Residential Rate Analysis – Flat Rates

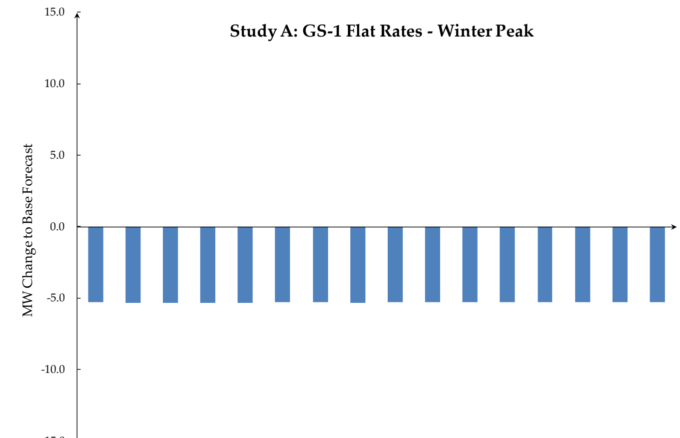
Study A: Flat Rates

Flat rates over all seasons result in a small decrease of the total bill to low usage customers (<1,400 kWh) in both the winter and the summer; however, high usage customers would expect to see bill increases in the winter and a smaller percentage reduction in the summer. The peak impacts project a decrease in the winter and a larger increase in the summer. Sales are impacted in a negative manner, which is reflective of the summer decrease in rate which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units.

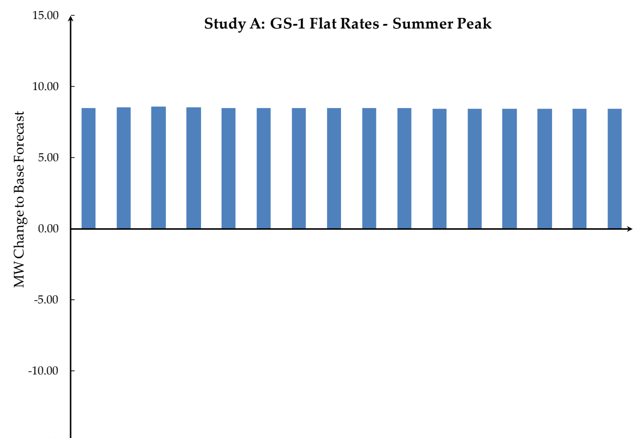




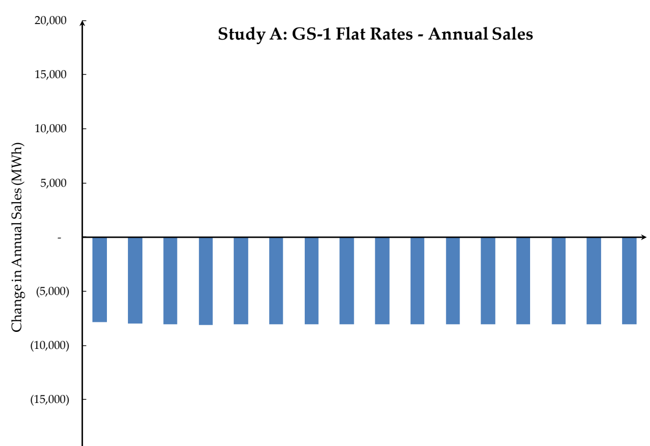
Appendix 2M.1 cont. – Non-Residential Rate Analysis – Flat Rates



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	-5.29	-5.34	-5.36	-5.36	-5.33	-5.31	-5.31	-5.32	-5.31	-5.30	-5.30	-5.29	-5.29	-5.29	-5.28	-5.28



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	8.51	8.56	8.57	8.54	8.49	8.48	8.49	8.49	8.48	8.47	8.45	8.45	8.45	8.44	8.44	8.44

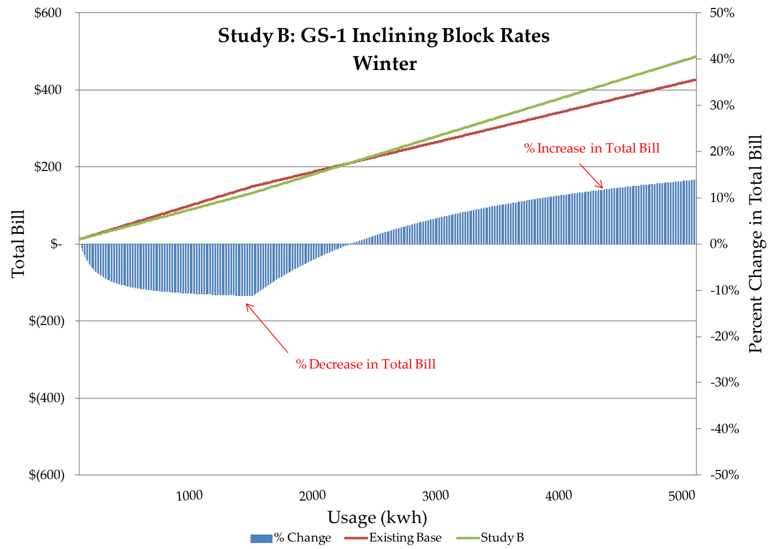


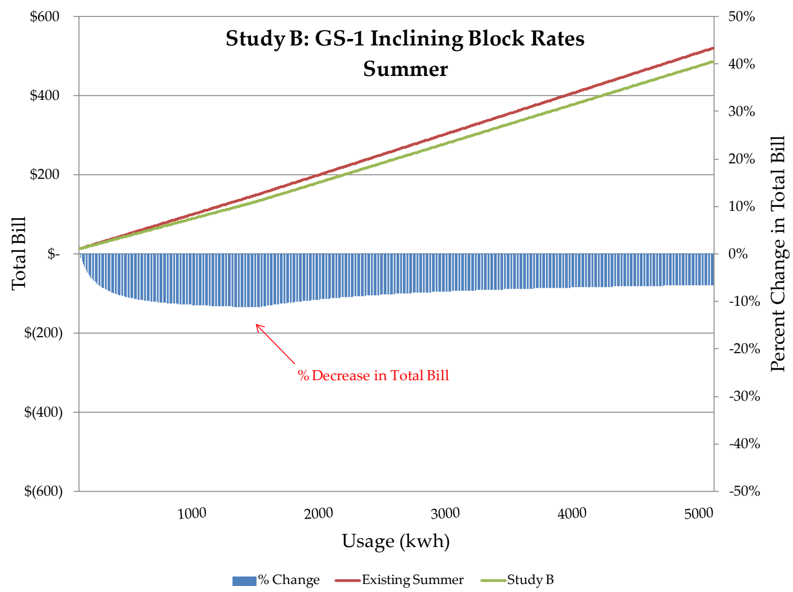
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study A	(7,862)	(7,964)	(8,048)	(8,073)	(8,052)	(8,015)	(8,036)	(8,045)	(8,045)	(8,039)	(8,032)	(8,028)	(8,029)	(8,035)	(8,039)	(8,044)

Appendix 2M.2 – Non-Residential Rate Analysis – Inclining Block Rates

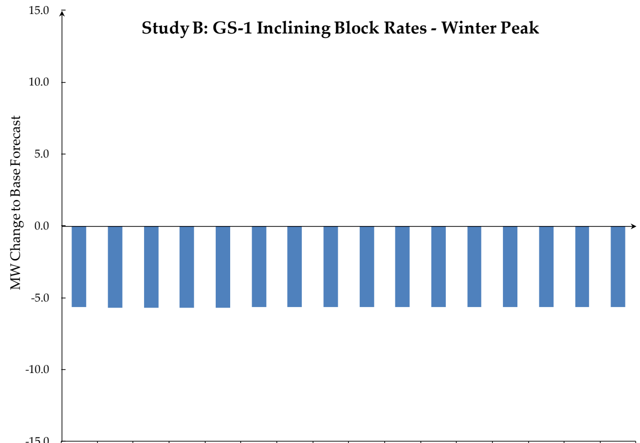
Study B: Inclining Block Rates

Inclining block rates over all seasons result in a fairly significant decrease to low usage customers (<1,400 kWh) in both the winter and the summer; however, the bills for high usage customers would increase significantly in the winter with a smaller reduction in the summer. The peak impacts show a decrease in the winter and a larger increase in the summer. Total annual sales are negatively impacted by the winter rate increase in the tail block which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units.

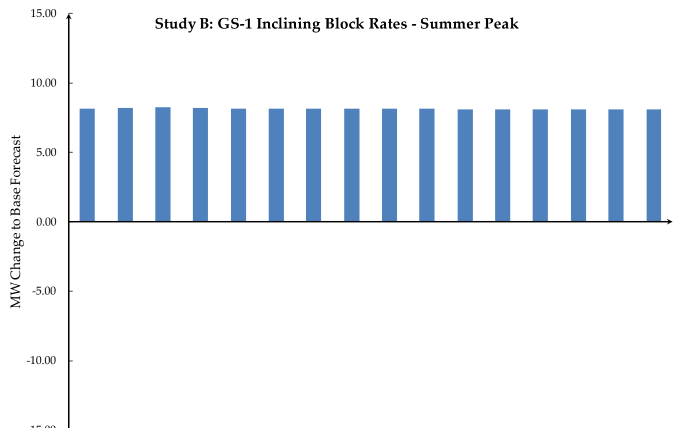




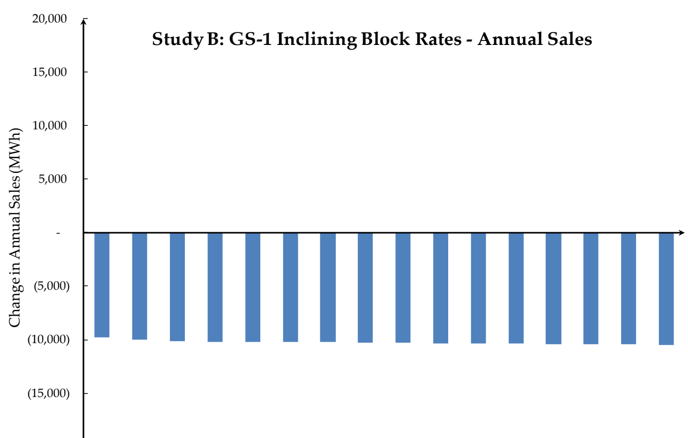
Appendix 2M.2 cont. – Non-Residential Rate Analysis – Inclining Block Rates



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	-5.63	-5.68	-5.70	-5.70	-5.67	-5.65	-5.65	-5.66	-5.65	-5.64	-5.63	-5.63	-5.62	-5.62	-5.62	-5.62



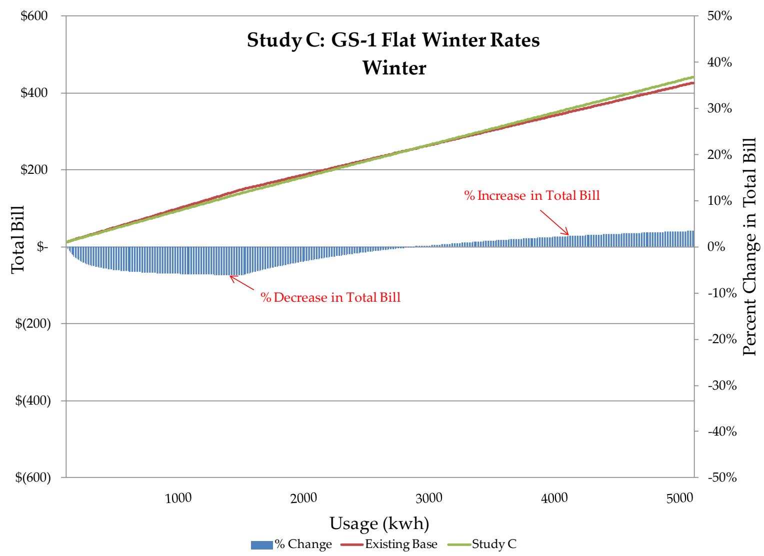
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	8.17	8.21	8.23	8.20	8.15	8.15	8.15	8.15	8.14	8.13	8.12	8.11	8.11	8.10	8.10	8.10

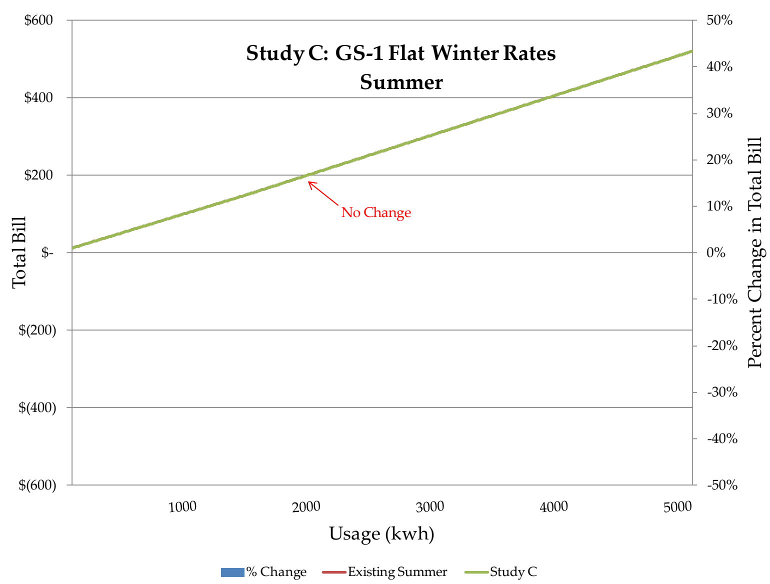


	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study B	(9,818)	(9,995)	(10,138)	(10,196)	(10,190)	(10,182)	(10,239)	(10,280)	(10,306)	(10,324)	(10,342)	(10,365)	(10,394)	(10,427)	(10,459)	(10,491)

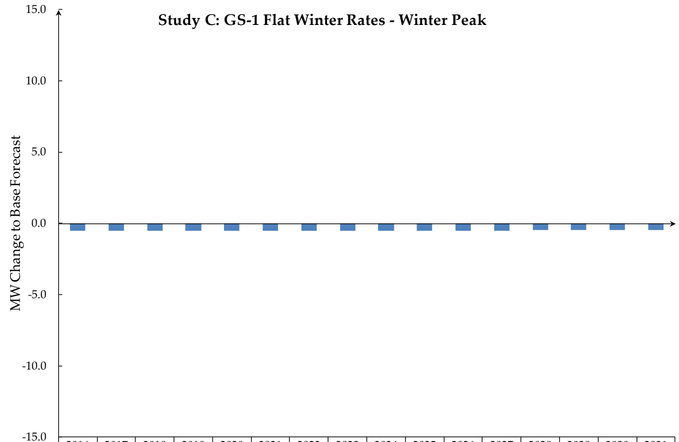
Appendix 2M.3 – Non-Residential Rate Analysis – Flat Winter Rates (No Change to Summer)

Study C: Flat Winter Generation Rates (No Change to Summer)
Flat winter rates with no change in the existing summer rate results in a small decrease in the total bill of low usage customers (<1,400 kWh) in the winter; however, the bills for high usage customers increase slightly in the winter. No customers' bills would change in the summer period under the assumptions in the study. Winter peaks are slightly reduced and summer peaks are unchanged. Annual sales are also reduced which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units.

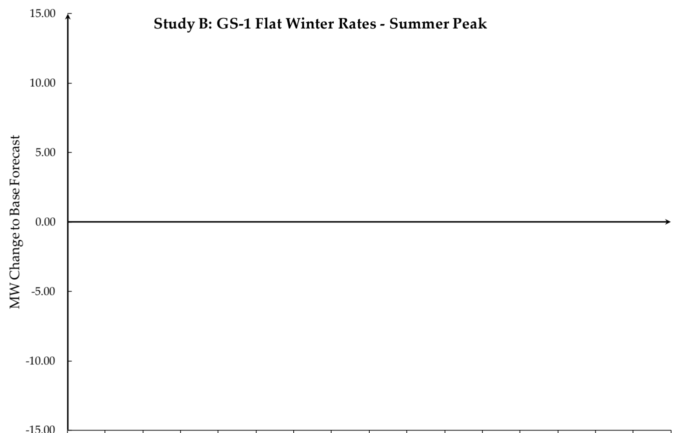




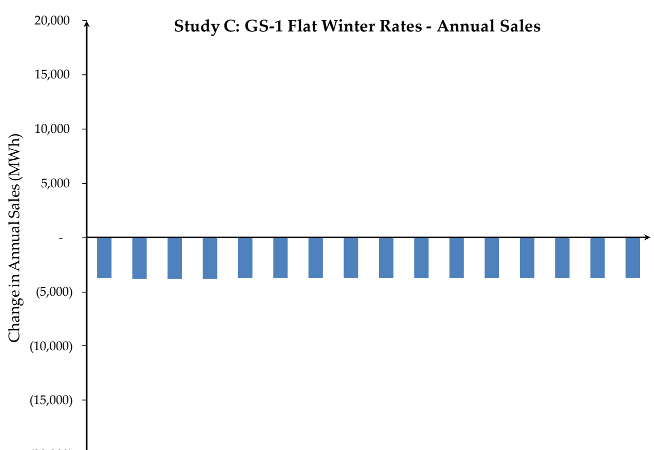
Appendix 2M.3 cont. – Non-Residential Rate Analysis – Flat Winter Rates (No Change to Summer)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

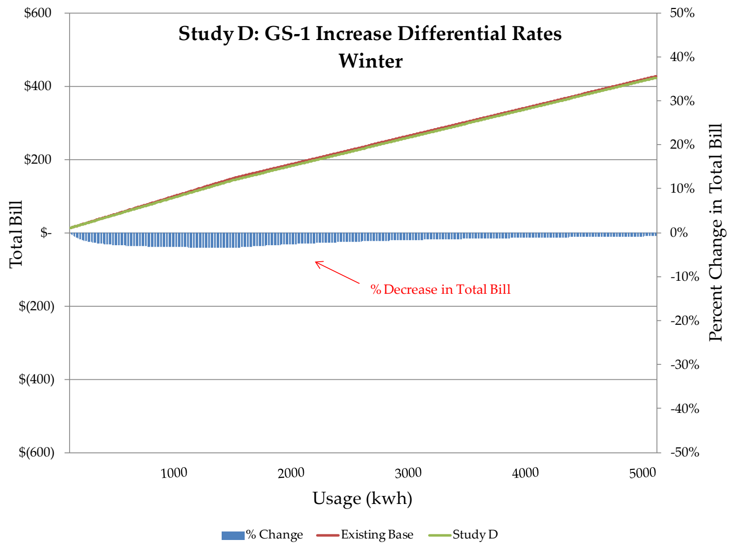


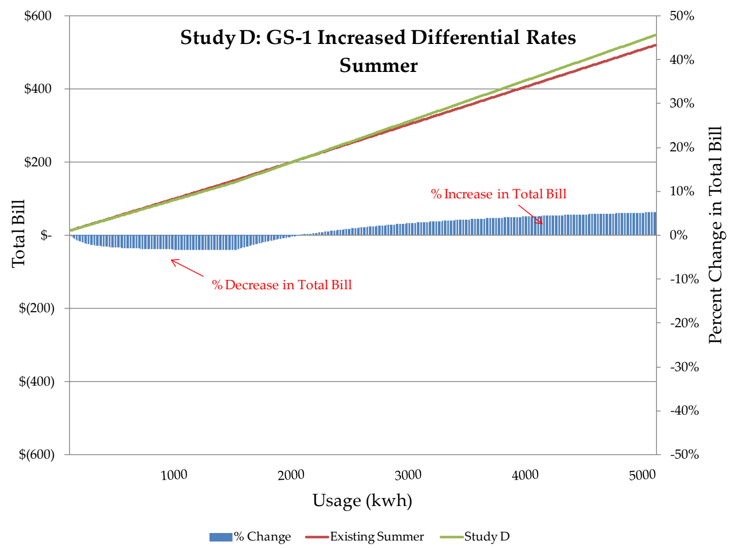
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study C	(3,755)	(3,781)	(3,794)	(3,785)	(3,766)	(3,761)	(3,765)	(3,767)	(3,762)	(3,756)	(3,751)	(3,750)	(3,748)	(3,747)	(3,747)	(3,747)

Appendix 2M.4 – Non-Residential Rate Analysis – Summer/Winter Differential Increased

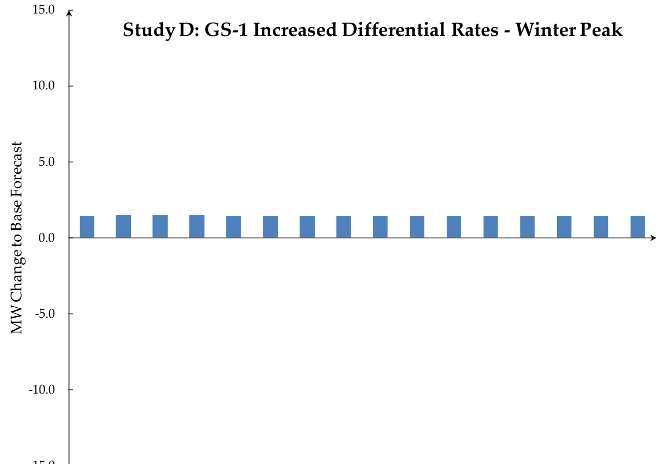
Study D: Summer/Winter Differential Increased

Increasing the summer/winter rate differential (summer increase/winter decrease) impacts customers below 1,400 kWh of monthly usage with a slight reduction in total bills during the winter and summer. Customers above 1,400 kWh of monthly usage will experience a slight reduction in total winter bills and a slight increase in total summer bills. Summer peak is less, but winter peaks are higher. Total annual sales would decrease which, in isolation, could result in lower base rates due to costs being recovered over more sales units.

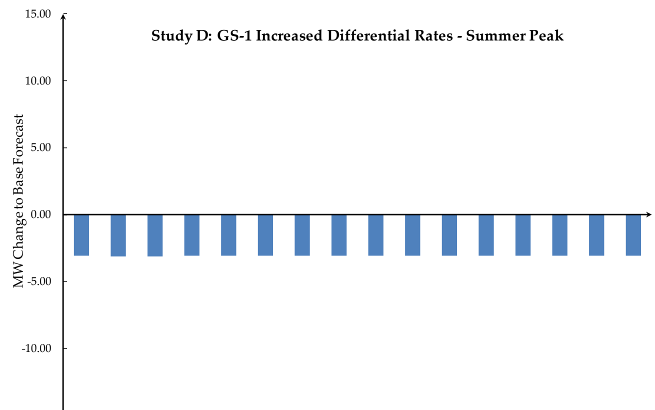




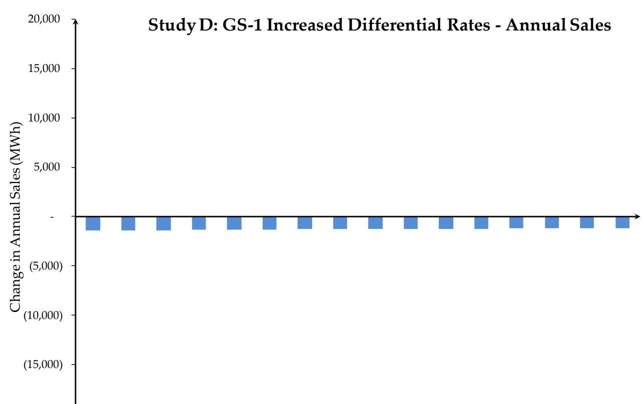
Appendix 2M.4 cont. – Non-Residential Rate Analysis – Summer/Winter Differential Increased



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	1.44	1.46	1.46	1.46	1.46	1.45	1.45	1.45	1.45	1.45	1.45	1.44	1.44	1.44	1.44	1.44



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	-3.08	-3.10	-3.11	-3.09	-3.08	-3.07	-3.08	-3.08	-3.07	-3.07	-3.06	-3.06	-3.06	-3.06	-3.06	-3.06

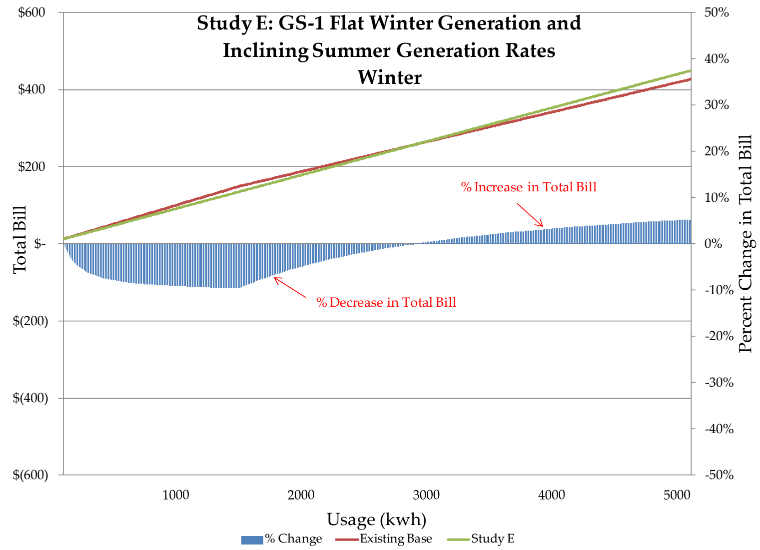


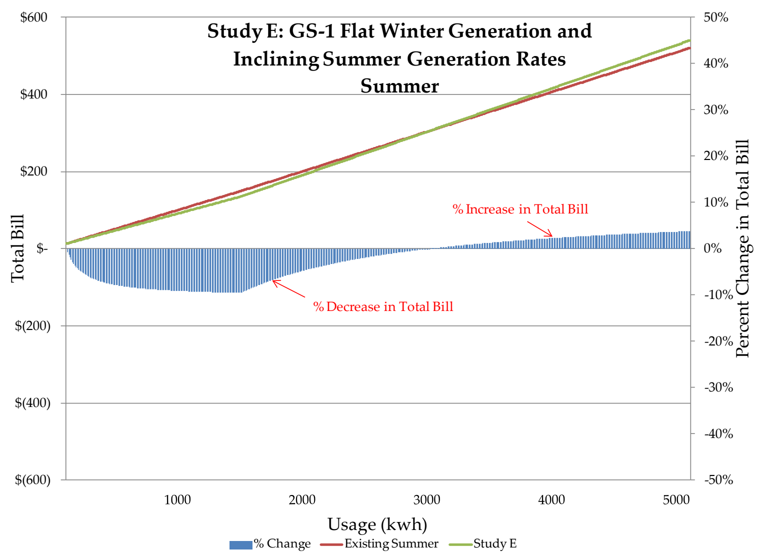
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study D	(1,432)	(1,401)	(1,364)	(1,330)	(1,306)	(1,302)	(1,286)	(1,273)	(1,257)	(1,242)	(1,229)	(1,218)	(1,205)	(1,191)	(1,179)	(1,167)

Appendix 2M.5 – Non-Residential Rate Analysis – Flat Winter Generation and Inclining Summer Generation

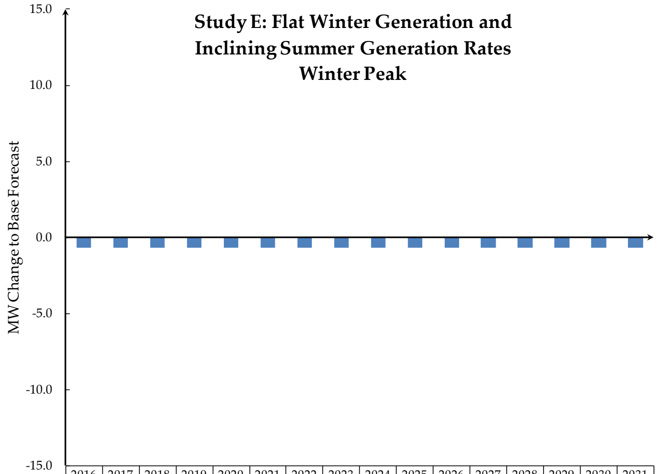
Study E: Flat Winter Generation and Inclining Summer Generation

Flat winter generation and increasing summer generation impacts users below 1,400 kWh per month with a reduction in total bills during the winter and summer periods. Higher usage customers experience slightly higher total bills in both the winter and the summer. Winter and summer peaks are reduced. Total annual sales are reduced which, in isolation, could result in lower base rates due to costs being recovered over more sales units.

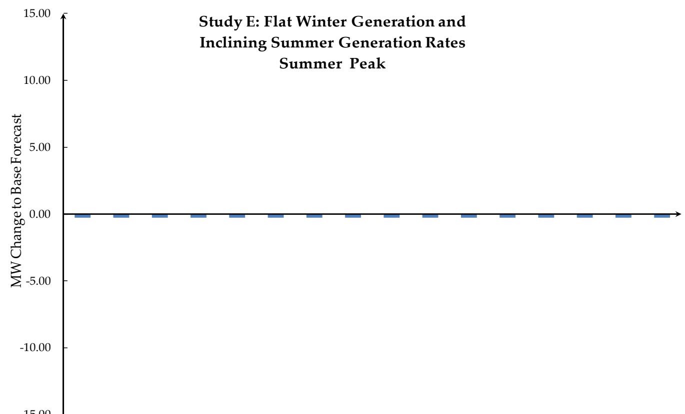




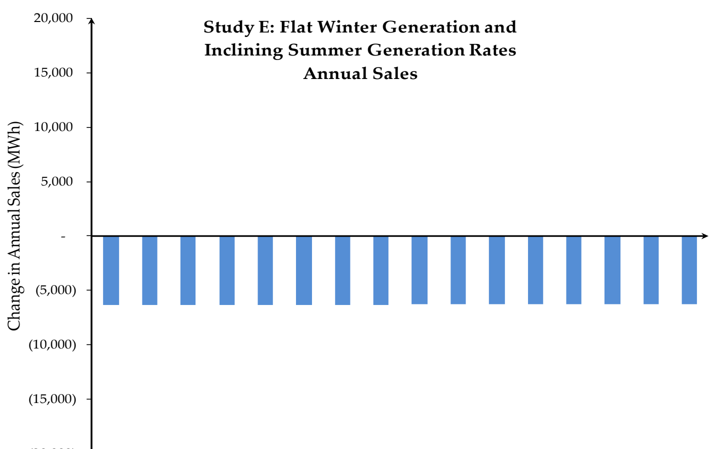
Appendix 2M.5 cont. – Non-Residential Rate Analysis – Flat Winter Generation and Inclining Summer Generation



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	-0.69	-0.70	-0.70	-0.70	-0.70	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69	-0.69



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Study E	(6,308)	(6,349)	(6,366)	(6,348)	(6,315)	(6,306)	(6,312)	(6,314)	(6,305)	(6,293)	(6,284)	(6,281)	(6,277)	(6,274)	(6,273)	(6,273)

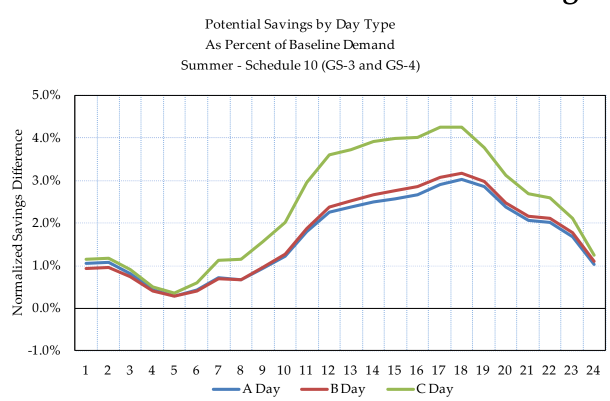
Appendix 2M.6 – Non-Residential Rate Analysis – Schedule 10

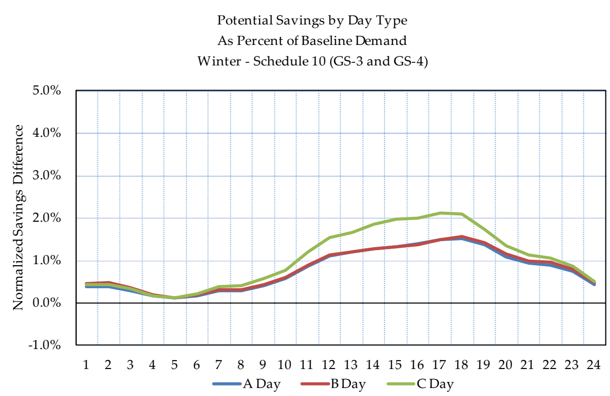
Study F: Schedule 10
Increase the on-peak rate for "A" days during the peak and off-peak seasons with no change to the off-peak rate. Reduce the peak and off-peak rates for "B" and "C" days for both the peak and off-peak seasons.

The Schedule 10 model results, as shown below, effectively predict energy consumption savings over all day types ("A/B/C") during peak and non-peak seasons when compared to the current Schedule 10 baseline demand. The Company developed an econometric model that links hourly shaped GS-3 and GS-4 sales to the alternate Schedule 10 rate, including weather and calendar variables, to assess the potential impact of an alternate rate schedule on GS-3 and GS-4 demand and usage curtailment. A regression analysis was performed on a sizeable sample of billing data that ranges from January 2012 to the end of 2015.

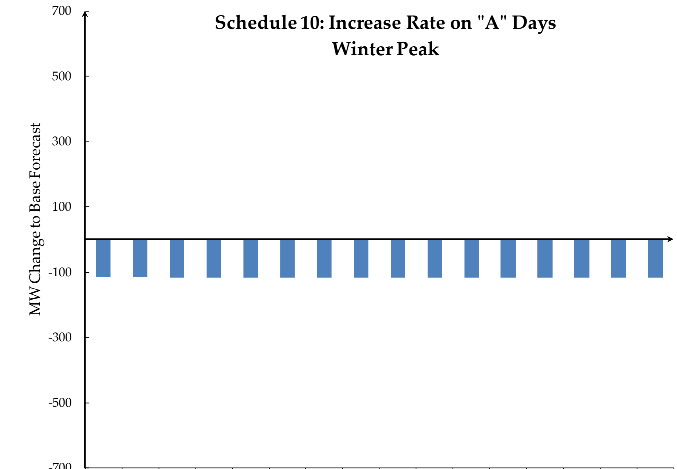
The findings suggest that most of the curtailment occurs on summer weekdays, between hour 10:00 AM and 6:00 PM. The peak demand is being reduced by an average of 80 MW, however, the annual usage increases by 0.8% due to the predominance of C-type days during the shoulder months. Increased total annual sales could, in turn, result in lower base rates due to costs being recovered over additional sales units.

Modeled 2015 Potential Savings by Day Type as Percent of Baseline Demand during Peak Months

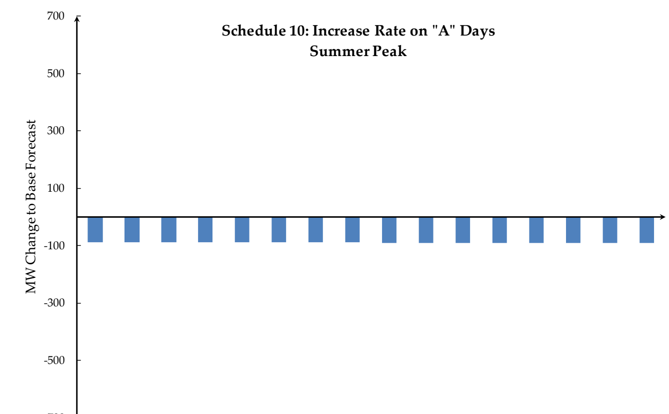




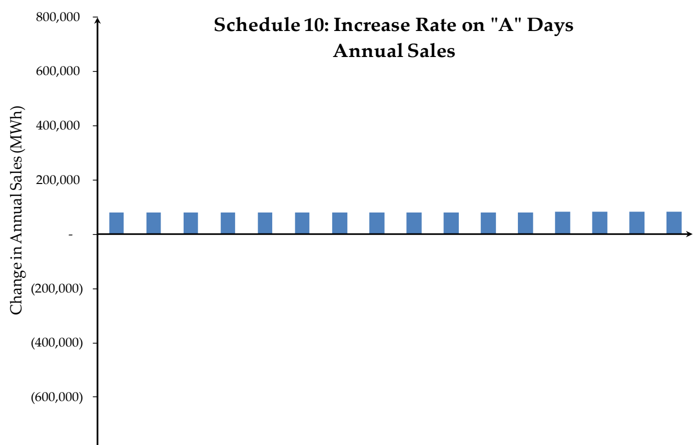
Appendix 2M.6 cont. – Non-Residential Rate Analysis – Schedule 10



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Schedule 10	-115	-116	-116	-116	-116	-116	-116	-116	-117	-117	-117	-117	-117	-117	-117	-118



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Schedule 10	-89	-89	-89	-89	-89	-89	-89	-89	-89	-90	-90	-90	-90	-90	-90	-90



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Schedule 10	80,380	80,481	80,581	80,682	80,783	80,884	80,985	81,086	81,188	81,289	81,391	81,492	81,594	81,696	81,798	81,901

Appendix 2N – Dynamic Pricing Rate Design Analysis

Residential Dynamic Pricing Rate Design:

This study presents the results of an analysis to implement dynamic pricing in lieu of Schedule 1 rates for the residential population in Virginia. Alternative rate designs are intended to be revenue neutral on a rate design basis and were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models. This study should not be interpreted as an alternative rate design proposal by the Company for the revision of the Company's Schedule 1 rates.

Modeling Approach:

The Company examined energy usage data from approximately 20,000 residential customers with AMI meters on Schedule 1 rates and developed a regression model to predict the effects of different pricing signals on peak and energy demand for calendar year 2015. The Company used the same cooling/heating season periods, "A/B/C "day classifications and dynamic rates that were used in the Company's DPP. Unfortunately, this regression modeling approach was necessary because data obtained from the actual DPP customers resulted in a price elasticity that was counterintuitive because as prices increased, demand increased. This may be the result of data bias due to a small sample size. Given this perceived anomaly in the DPP customer data, the Company elected to complete this analysis using the regression modeling method described above.

Residential Dynamic Pricing Billing Determinants:

- Three day classifications – High-Priced ("A"), Medium-Priced ("B") and Low-Priced ("C"). The kWh charges vary by time of day, day classification and season (cooling vs. heating).
- On "A" days in the cooling season (April 16 – October 15), there are three pricing periods – On-peak (1 pm – 7 pm), shoulder periods (10 am – 1 pm & 7 pm – 10 pm), and Off-peak (10 pm – 10 am). During the heating season (October 16 – April 15), there are two pricing periods - On-peak (5 am – 11 am & 5 pm – 10 pm) and Off-peak (11 am – 5 pm & 10 pm – 5 am).
- On "B" days in the cooling season (April 16 – October 15), there are two pricing periods – On-peak (10 am – 10 pm) and Off-peak (10 pm – 10 am). During the heating season (October 16 – April 15), there are two pricing periods - On-peak (5 am – 11 am & 5 pm – 10 pm) and Off-peak (11 am – 5 pm & 10 pm – 5 am).
- On "C" days in the cooling season (April 16 – October 15), there are two pricing periods – On-peak (10 am – 10 pm) and Off-peak (10 pm – 10 am). During the heating season (October 16 – April 15), there are two pricing periods - On-peak (5 am – 11 am & 5 pm – 10 pm) and Off-peak (11 am – 5 pm & 10 pm – 5 am).
- Demand charges apply in all months.

Appendix 2N cont. – Dynamic Pricing Rate Design Analysis

A side-by-side comparison of the dynamic pricing rates and the expected number of "A" days, "B" days, and "C" days compared to Schedule 1 block rates for residential customers is shown in the figure below.

Residential Dynamic Pricing Rate Design

Schedule 1 Base Rates	Schedule 1 Rates (effective 1/1/2016)
DISTRIBUTION CHARGES	
Basic Customer Charge	$ 7.00
Energy Charge - Summer	
First 800 kWh-Summer	$ 0.02244
Add'l Peak kWh-Summer	$ 0.01271
Energy Charge - Winter (Base)	
First 800 kWh-Base	$ 0.02244
Add'l Peak kWh-Base	$ 0.01271
GENERATION CHARGES	
Energy - Summer	
First 800 kWH	$ 0.03795
Over 800 kWH	$ 0.05773
Energy - Winter (Base)	
First 800 kWH	$ 0.03795
Over 800 kWH	$ 0.02927
GENERATION RIDERS (RAC)	
A6 - Rider - Gen Rider B	$ 0.000150
A6 - Rider - Gen Rider BW	$ 0.001600
A6 - Rider - Gen Rider R	$ 0.001429
A6 - Rider - Gen Rider S	$ 0.004180
A6 - Rider - Gen Rider W	$ 0.002300
SUBTOTAL GEN RIDERS:	$ 0.009659
NON-GEN RIDERS	
A4 - Transmission	$ 0.01354
A5 - DSM	$ 0.00068
Fuel Rider A	$ 0.02406
SUBTOTAL NON-GEN RIDERS:	$ 0.03828

Dynamic Pricing Rates Effective 1/1/2016	"A" Days	"B" Days	"C" Days
	30 Days	55 Days	280 Days
DISTRIBUTION CHARGES			
Basic Customer Charge	$ 7.00	$ 7.00	$ 7.00
Energy Charge (per kWh)	$ 0.00381	$ 0.00381	$ 0.00381
Demand Charge (per kW)	$ 2.05900	$ 2.05900	$ 2.05900
TRANSMISSION CHARGES			
Energy Charge (per kWh)	$ 0.00970	$ 0.00970	$ 0.00970
GENERATION CHARGES			
COOLING SEASON (per kWh)	April 16 - October 15		
12 am - 10 am	$ 0.02620	$ 0.01429	$ 0.00338
10 am - 1 pm	$ 0.08962	$ 0.05742	$ 0.02693
1 pm - 7 pm	$ 0.49102	$ 0.05742	$ 0.02693
7 pm - 10 pm	$ 0.08962	$ 0.05742	$ 0.02693
10 pm - 12 am	$ 0.02620	$ 0.01429	$ 0.00338
HEATING SEASON (per kWh)	October 16 - April 15		
5 am - 11 am	$ 0.30392	$ 0.05835	$ 0.02562
11 am - 5 pm	$ 0.05289	$ 0.03181	$ 0.00964
5 pm - 10 pm	$ 0.30392	$ 0.05835	$ 0.02562
10 pm - 5 am	$ 0.05289	$ 0.03181	$ 0.00964
GENERATION RIDERS (RAC)			
A6 - Rider - Gen Rider B	$ 0.000150	$ 0.000150	$ 0.000150
A6 - Rider - Gen Rider BW	$ 0.001600	$ 0.001600	$ 0.001600
A6 - Rider - Gen Rider R	$ 0.001429	$ 0.001429	$ 0.001429
A6 - Rider - Gen Rider S	$ 0.004180	$ 0.004180	$ 0.004180
A6 - Rider - Gen Rider W	$ 0.002300	$ 0.002300	$ 0.002300
SUBTOTAL GEN RIDERS:	$ 0.009659	$ 0.009659	$ 0.009659
NON-GEN RIDERS			
A4 - Transmission	$ 0.01354	$ 0.01354	$ 0.01354
A5 - DSM	$ 0.00068	$ 0.00068	$ 0.00068
Fuel Rider A	$ 0.02406	$ 0.02406	$ 0.02406
SUBTOTAL NON-GEN RIDERS:	$ 0.03828	$ 0.03828	$ 0.03828

Appendix 2N cont. – Dynamic Pricing Rate Design Analysis

Residential Dynamic Pricing Results

The dynamic pricing regression modeling results follow expectations such that increases in prices lead to lower peak demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities is approximately -0.75, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.75%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure system peak levels. Such an impact from recognition of a price elasticity effect on the generation and resource plan should also be recognized in the design of electricity rates. Price signals (A, B or C day types) are not expected to be uniform across the year because of the weighted average effect of seasonal usage levels (peak and shoulder months) and the different period of cooling (6 months) and heating (6 months) seasonal rates. The C-days rate structure is predominately seen in shoulder months to incentivize customers on the dynamic rate to use energy when dynamic pricing rates are the lowest. The -0.75 price elasticity determined in this analysis is extraordinarily high, however, and also questionable as to its validity. This is likely the result of developing the regression model with data from customers who are currently being serviced under Schedule 1 rates. A more appropriate model would be one developed using data from customers that are currently on DPP rates but, as was mentioned previously, the results from the regression model using the actual data from DPP customers produced counterintuitive results and could not be utilized in this analysis.

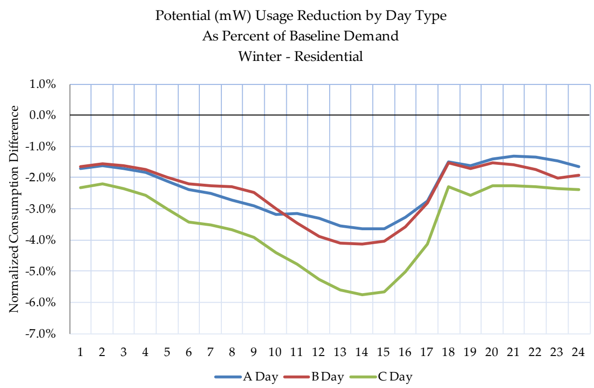
> 1% increase in the average residential price of electricity would decrease average consumption by approximately 0.75%.

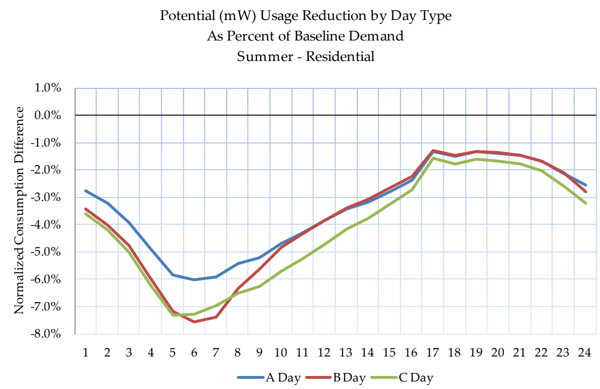
Econometric analysis of the residential response to different price signals effectively suggests a decrease in peak demand and usage during peak months and a net kWh usage increase during shoulder months.

The residential dynamic pricing model results, as shown below, effectively predict reduced energy consumption over all day types ("A/B/C") during peak months for 2015 when compared to Schedule 1 baseline demand. During "A" days of peak months, energy savings on average are generally less than "B" or "C" days. This result implies that customers are less willing to curtail during periods of extreme weather when their load is generally greater. Even though customers may respond to the higher price signal, they will not necessarily sacrifice comfort by significantly reducing their cooling or heating load.

Appendix 2N cont. – Dynamic Pricing Rate Design Analysis

Modeled 2015 (MW) Peak Reduction by Day Type as Percent of Baseline Demand





Dynamic Pricing Assumptions for Cost Sensitivity Analysis

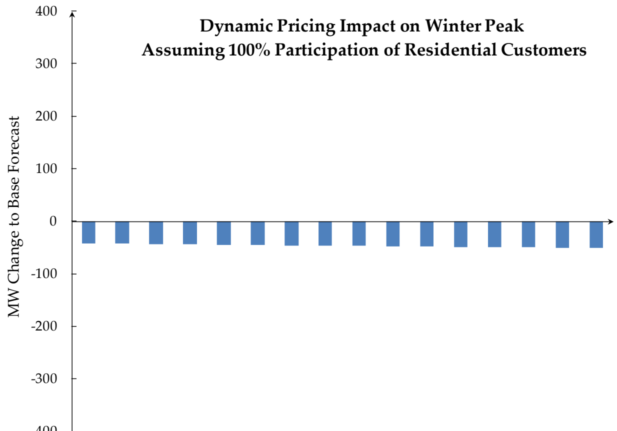
1. AMI meters are fully deployed throughout the Company's service territory. The estimated cost is approximately $350 million and is not included in this analysis.
2. Billing system and interval data processing infrastructure are each upgraded to facilitate customer billing using interval meter data. The estimated cost is approximately $6.8 million and is not included in this analysis.
3. Assume 100% of residential customers enroll in dynamic pricing rate. While the Company acknowledges that 100% residential participation is not practical, the model was not designed to interpret incremental participation rates.
4. Assumed Dynamic pricing rates would be identical to that which was offered in the DPP.

Full implementation of dynamic pricing to 100% of the Company's residential customers would potentially decrease the system peak demand by an average of 0.3% the first year and increase total annual residential usage by approximately 1% and total expected system sales by 0.4%. The dynamic pricing impact charts shown below reflect the estimated change in seasonal peak for the cooling season (April 16 – October 15), heating season (October 16 – April 15) and annual sales from 2016 through 2031, due to the change in annual rates over time.

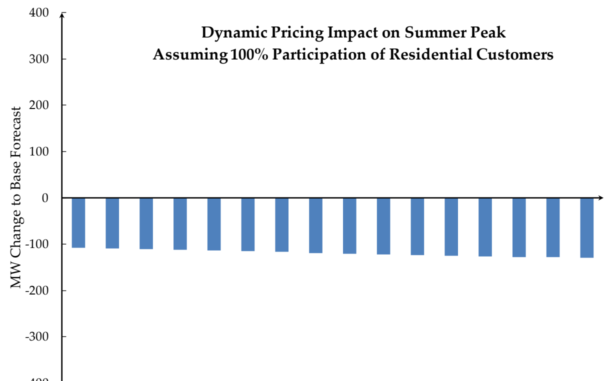
Appendix 2N cont. – Dynamic Pricing Rate Design Analysis

Dynamic Pricing Impact Charts

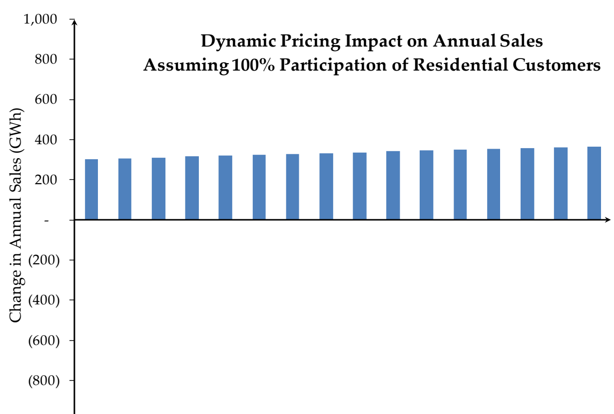
Winter and summer peak decreases moderately, but total annual sales increase. Increased total annual sales could, in turn, result in lower base rates due to costs being recovered over additional sales units.



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DPR	-42	-43	-43	-44	-45	-45	-46	-47	-47	-48	-48	-49	-49	-50	-50	-51



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DPR	-108	-109	-111	-113	-114	-116	-117	-119	-120	-122	-123	-125	-126	-127	-128	-130



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DPR	303	307	312	316	320	324	329	333	338	342	346	349	353	357	360	364

Appendix 3A – Existing Generation Units in Service for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Altavista	Altavista, VA	Base	Renewable	Feb-1992	51	51
Bath County Units 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,808	1,808
Bear Garden	Buckingham County, VA	Intermediate	Natural Gas-CC	May-2011	590	622
Bellemeade	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	267	267
Bremo 3	Bremo Bluff, VA	Peak	Natural Gas	Jun-1950	71	74
Bremo 4	Bremo Bluff, VA	Peak	Natural Gas	Aug-1958	156	161
Brunswick	Brunswick County, VA	Intermediate	Natural Gas-CC	May-2016	1,368	1,509
Chesapeake CT 1, 2, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	51	69
Chesterfield 3	Chester, VA	Base	Coal	Dec-1952	98	102
Chesterfield 4	Chester, VA	Base	Coal	Jun-1960	163	168
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336	342
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	670	690
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197	226
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	200	236
Clover 1	Clover, VA	Base	Coal	Oct-1995	220	222
Clover 2	Clover, VA	Base	Coal	Mar-1996	219	219
Cushaw Hydro	Big Island, VA	Intermediate	Hydro-Conventional	Jan-1930	2	3
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	98
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	97
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	95
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	97
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	121
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	120
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	124
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	135
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	133
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28	38
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85	98
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	97
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	98
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85	97
Hopewell	Hopewell, VA	Base	Renewable	Jul-1989	51	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161	183
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160	183
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160	183
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48	65
Mecklenburg 1	Clarksville, VA	Base	Coal	Nov-1992	69	69
Mecklenburg 2	Clarksville, VA	Base	Coal	Nov-1992	69	69

(1) Commercial Operation Date.

Appendix 3A cont. – Existing Generation Units in Service for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	554	569
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	555	570
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520	537
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11	15
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838	868
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834	863
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Pittsylvania	Hurt, VA	Base	Renewable	Jun-1994	83	83
Possum Point 3	Dumfries, VA	Peak	Natural Gas	Jun-1955	96	100
Possum Point 4	Dumfries, VA	Peak	Natural Gas	Apr-1962	220	225
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	786	805
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	573	615
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72	106
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153	187
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151	187
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	187
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	188
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95	95
Rosemary	Roanoke Rapids, NC	Intermediate	Natural Gas-CC	Dec-1990	165	186
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	2	2
Southampton	Franklin, VA	Base	Renewable	Mar-1992	51	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838	875
Surry 2	Surry, VA	Base	Nuclear	May-1973	838	875
Virginia City Hybrid Energy Center[2]	Virginia City, VA	Base	Coal	Jul-2012	610	624
Warren	Warrenton, VA	Intermediate	Natural Gas-CC	Dec-2014	1,342	1,436
Yorktown 1	Yorktown, VA	Base	Coal	Jul-1957	159	162
Yorktown 2	Yorktown, VA	Base	Coal	Jan-1959	164	165
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	790	792
Subtotal - Base					7,990	8,224
Subtotal - Intermediate					7,046	7,492
Subtotal - Peak					4,791	5,326
Subtotal - Intermittent					2	2
Total					19,829	21,045

(1) Commercial Operation Date.

Appendix 3B – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units[1]							
Spruance Genco, Facility 1 (Richmond 1)	Richmond, VA	Base	Coal	115,500	Yes	8/1/1992	7/31/2017
Spruance Genco, Facility 2 (Richmond 2)	Richmond, VA	Base	Coal	85,000	Yes	8/1/1992	7/31/2017
Doswell Complex	Ashland, VA	Intermedia	Natural Gas	605,000	Yes	5/16/1992	5/5/2017
Roanoke Valley II	Weldon, NC	Base	Coal	44,000	Yes	6/1/1995	3/31/2019
Roanoke Valley Project	Weldon, NC	Base	Coal	165,000	Yes	5/29/1994	3/31/2019
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter (BTM) Generation Units							
BTM Alexandria/Arlington - Covanta	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
BTM Brasfield Dam	VA	Must Take	Hydro	2,500	No	10/12/1993	Auto renew
BTM Suffolk Landfill	VA	Must Take	Methane	3,000	No	11/4/1994	Auto renew
BTM Columbia Mills	VA	Must Take	Hydro	343	No	2/7/1985	Auto renew
BTM Schoolfield Dam	VA	Must Take	Hydro	2,500	No	12/1/1990	Auto renew
BTM Lakeview (Swift Creek) Dam	VA	Must Take	Hydro	400	No	11/26/2008	Auto renew
BTM MeadWestvaco (formerly Westvaco)	VA	NUG	Coal/Biomass	140,000	No	11/3/1982	12/31/2028
BTM Banister Dam	VA	Must Take	Hydro	1,785	No	9/28/2008	Auto renew
BTM Jockey's Ridge State Park	NC	Must Take	Wind	10	No	5/21/2010	Auto renew
BTM 302 First Flight Run	NC	Must Take	Solar	3	No	5/5/2010	Auto renew
BTM 3620 Virginia Dare Trail N	NC	Must Take	Solar	4	No	9/14/2009	Auto renew
BTM Weyerhaeuser/Domtar	NC	NUG	Coal/biomass	28400[2]	No	7/27/1991	Auto renew
BTM Chapman Dam	VA	Must Take	Hydro	300	No	10/17/1984	Auto renew
BTM Smurfit-Stone Container	VA	NUG	Coal/biomass	48400[3]	No	3/21/1981	Auto renew
BTM Rivanna	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
BTM Rapidan Mill	VA	Must Take	Hydro	100	No	6/15/2009	Auto renew
BTM Dairy Energy	VA	Must Take	Biomass	400	No	8/2/2011	8/1/2016
BTM W. E. Partners II	NC	Must Take	Biomass	300	No	3/15/2012	3/14/2017
BTM Plymouth Solar	NC	Must Take	Solar	5,000	No	10/4/2012	10/3/2027
BTM W. E. Partners 1	NC	Must Take	Biomass	100	No	4/26/2013	4/25/2017
BTM Dogwood Solar	NC	Must Take	Solar	20,000	No	12/9/2014	12/8/2029

(1) In operation as of March 15, 2016.

(2) Agreement to provide excess energy only.

(3) PPA is for excess energy only, typically 4,000 – 14,000 kW.

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Behind-The-Meter (BTM) Generation Units							
BTM HXOap Solar	NC	Must Take	Solar	20,000	No	12/16/2014	12/15/2029
BTM Bethel Price Solar	NC	Must Take	Solar	5,000	No	12/9/2014	12/8/2029
BTM Jakana Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
BTM Lewiston Solar	NC	Must Take	Solar	5,000	No	12/18/2014	12/17/2029
BTM Williamston Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
BTM Windsor Solar	NC	Must Take	Solar	5,000	No	12/17/2014	12/16/2029
BTM 510 REPP One Solar	NC	Must Take	Solar	5,000	No	3/11/2015	3/10/2030
BTM Everetts Wildcat Solar	NC	Must Take	Solar	5,000	No	3/11/2015	3/10/2030
SolNC5 Solar	NC	Must Take	Solar	5,000	No	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Must Take	Solar	14,000	No	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Must Take	Solar	5,000	No	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Must Take	Solar	5,000	No	11/1/2015	10/31/2030
Downs Farm Solar	NC	Must Take	Solar	5,000	No	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Must Take	Solar	5,000	No	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Must Take	Solar	5,000	No	12/18/2015	12/17/2030
Green Farm Solar	NC	Must Take	Solar	5,000	No	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Must Take	Solar	20,000	No	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Must Take	Solar	20,000	No	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Must Take	Solar	5,000	No	2/4/2016	2/3/2031
Conetoe Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
SolNC3 Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
Gates Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Must Take	Solar	5,000	No	2/12/2016	2/11/2031
Battboro Farm Solar	NC	Must Take	Solar	5,000	No	2/17/2016	2/16/2031
Winton Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
SolNC10 Solar	NC	Must Take	Solar	5,000	No	1/13/2016	1/12/2031
Tarboro Solar	NC	Must Take	Solar	5,000	No	12/31/2015	12/30/2030
Bethel Solar	NC	Must Take	Solar	4,400	No	3/3/2016	3/2/2031

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	25000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	Natural Gas	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	VA Beach	Standby	Diesel	3500	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/ Natural Gas	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	Natural Gas	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	Natural Gas	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	Natural Gas	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	Natural Gas	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black Liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Natural Gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Ashburn	Standby	Diesel	22000	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	NG	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	Va Beach	Standby	Diesel	3500	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/NG	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	NG	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	NG	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	NG	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	NG	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Nat gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Norfolk	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Norfolk	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Newport News	Standby	Diesel	750	No	N/A	N/A
	Chesterfield	Standby	Coal	500	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Richmond Metro	Standby	NG	25000	No	N/A	N/A
	Suffolk	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	21000	No	N/A	N/A
	Richmond	Standby	Diesel	500	No	N/A	N/A
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A
	VA	Merchant	RDF	60000	No	N/A	N/A
	Stafford	Standby	Diesel	3000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	5150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A
	Hampton Roads	Standby	Unknown	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[(3)]							
	Northern VA	Standby	Diesel	13000	No	N/A	N/A
	Southside VA	Standby	Water	227000	No	N/A	N/A
	Northern VA	Standby	Diesel	300	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	30	No	N/A	N/A
	Newport News	Standby	Diesel	1000	No	N/A	N/A
	Hampton	Standby	Diesel	12000	No	N/A	N/A
	Newport News	Standby	Natural gas	3000	No	N/A	N/A
	Newport News	Standby	Diesel	2000	No	N/A	N/A
	Petersburg	Standby	Diesel	1750	No	N/A	N/A
	Various	Standby	Diesel	3000	No	N/A	N/A
	Various	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	16000	No	N/A	N/A
	Northern VA	Standby	Diesel	6450	No	N/A	N/A
	Virginia Beach	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	12 - 2000	No	N/A	N/A
	Innsbrook-Richmond	Standby	Diesel	6050	No	N/A	N/A
	Northern VA	Standby	Diesel	150	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Virginia Beach	Standby	Diesel	1500	No	N/A	N/A
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	30000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A

Appendix 3C – Equivalent Availability Factor for Plan B: Intensity-Based Dual Rate (%)

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Altavista	55	55	67	78	88	88	88	88	90	88	88	88	88	88	88	88	88	88	93
Bath County Units 1-6	84	78	77	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden	91	79	81	89	84	90	80	86	90	89	88	89	88	90	89	88	89	77	90
Bellemeade	85	70	83	87	71	80	91	91	88	87	89	87	87	89	89	87	89	87	89
Bremo 3	62	65	78	89	85	93	83	86	90	93	86	93	86	93	86	86	93	86	89
Bremo 4	56	53	80	85	85	92	83	80	77	92	85	92	85	92	85	92	85	92	88
Brunswick	-	-	-	90	84	86	91	86	86	88	88	83	88	76	88	88	83	88	89
Chesapeake CT 1, 2, 4, 6	96	95	92	88	88	88	88	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	83	81	85	85	81	91	83	91	85	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	68	92	65	84	84	82	85	89	80	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	71	77	83	83	88	85	83	88	88	83	88	88	83	88	88	83	88	88	83
Chesterfield 6	87	73	84	89	79	86	91	78	91	91	78	89	91	78	89	91	78	89	86
Chesterfield 7	91	79	90	72	96	89	96	89	96	91	96	91	96	89	96	80	96	91	96
Chesterfield 8	94	80	90	72	96	88	96	89	92	80	96	89	96	88	96	89	96	88	96
Clover 1	98	93	76	93	94	91	92	94	92	94	94	86	93	94	86	94	94	86	86
Clover 2	94	80	90	93	83	94	92	86	84	93	86	94	93	86	94	93	86	94	95
Cushaw Hydro	62	52	56	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Darbytown 1	96	88	96	94	94	94	67	94	94	90	90	90	90	90	90	90	90	90	92
Darbytown 2	98	93	80	94	94	94	83	94	94	90	90	90	90	90	90	90	90	90	92
Darbytown 3	99	94	91	94	92	94	83	94	94	90	90	90	90	90	90	90	90	90	92
Darbytown 4	97	95	92	94	94	94	83	94	94	90	90	90	90	90	90	90	90	90	92
Doswell Complex	87	86	85	95	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	93	72	99	94	82	94	94	90	94	90	90	90	90	90	90	90	90	90	90
Elizabeth River 2	93	64	97	94	82	94	91	94	94	90	90	90	90	90	90	90	90	90	90
Elizabeth River 3	94	82	99	67	78	90	94	94	88	90	90	90	90	90	90	90	90	90	90
Existing NC Solar NUGs	-	-	20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Gaston Hydro	86	91	88	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Generic 3x1 CC 2022	-	-	-	-	-	-	-	-	-	88	88	88	88	88	88	88	88	88	88
Generic 3x1 CC 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	88
Generic 3x1 CC 2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	88	88	88	88	88	88	88	88	88
Generic CT 2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	94	74	81	87	96	84	93	93	96	85	96	91	96	85	96	91	96	85	96
Gordonsville 2	94	85	83	93	84	84	93	93	91	91	96	91	96	84	91	96	91	96	96
Gravel Neck 1-2	96	88	96	88	88	88	88	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	72	94	89	94	94	94	94	94	94	90	90	90	90	90	90	90	90	90	94
Gravel Neck 4	98	96	90	94	94	94	94	92	94	90	90	90	90	90	90	90	90	90	94
Gravel Neck 5	98	95	92	94	94	94	92	94	94	90	90	90	90	90	90	90	90	90	94
Gravel Neck 6	98	97	91	94	94	94	94	94	94	90	90	90	90	90	90	90	90	90	94
Greensville	-	-	-	-	-	8	80	86	86	90	90	90	90	90	90	90	90	90	89
Hopewell	39	70	64	88	88	90	90	90	90	88	88	88	88	88	88	88	88	88	92
Ladysmith 1	81	96	93	92	90	90	90	90	90	90	90	90	90	90	90	90	90	92	89
Ladysmith 2	80	95	92	92	90	90	90	90	90	90	90	90	90	90	90	90	90	92	89
Ladysmith 3	94	90	94	92	87	82	90	90	90	90	90	90	90	90	90	90	90	90	89
Ladysmith 4	94	94	94	92	87	82	90	90	90	90	90	90	90	90	90	90	90	90	89
Ladysmith 5	95	92	94	90	87	82	90	90	90	90	90	90	90	90	90	90	90	90	89
Lowmoor CT 1-4	100	85	98	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	97	95	84	93	92	95	92	95	92	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	98	91	82	93	90	95	92	95	88	-	-	-	-	-	-	-	-	-	-

Appendix 3C cont. – Equivalent Availability Factor for Plan B: Intensity-Based Dual Rate (%)

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Mount Storm 1	74	91	80	79	89	90	86	90	85	76	81	90	89	81	90	89	81	85	81
Mount Storm 2	83	73	78	85	87	74	89	86	78	89	81	89	89	81	89	89	81	89	89
Mount Storm 3	79	82	79	71	91	91	89	86	89	91	81	91	91	81	91	91	81	91	90
Mount Storm CT	92	92	57	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	90	98	92	89	98	89	92	98	91	91	98	91	91	98	91	91	98	90	90
North Anna 2	86	90	100	89	89	98	89	91	98	91	91	98	91	91	98	91	91	98	90
North Anna Hydro	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Northern Neck CT 1-4	98	99	100	88	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	78	92	88	93	93	92	93	93	97	93	93	93	93	93	93	93	93	93	93
Possum Point 3	89	72	89	87	83	91	87	77	91	91	83	91	83	91	83	83	91	83	91
Possum Point 4	92	59	83	87	83	91	83	91	77	91	83	91	87	91	83	91	87	91	83
Possum Point 5	70	30	33	68	61	70	70	77	70	69	77	77	85	77	69	77	77	77	85
Possum Point 6	89	84	80	84	86	88	81	86	81	84	88	88	88	76	88	88	88	88	81
Possum Point CT 1-6	100	96	100	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	90	87	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	89
Remington 2	87	94	86	90	90	90	90	90	86	90	90	90	90	90	90	90	90	90	89
Remington 3	90	94	89	83	90	90	90	90	90	90	90	90	90	90	90	90	90	90	89
Remington 4	91	87	92	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	89
Roanoke Rapids Hydro	94	86	88	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Roanoke Valley II	87	96	92	89	89	89	87	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	85	87	90	87	87	87	95	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	85	76	68	91	89	96	96	83	83	96	89	96	89	96	89	96	89	96	89
SEI Birchwood	87	87	90	82	87	87	87	87	82	-	-	-	-	-	-	-	-	-	-
VA Solar 2020	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Solar 2020	-	-	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25
Solar 2021	-	-	-	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25
Solar 2022	-	-	-	-	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25
Solar 2023	-	-	-	-	-	-	-	-	-	-	25	25	25	25	25	25	25	25	25
Solar 2024	-	-	-	-	-	-	-	-	-	-	-	25	25	25	25	25	25	25	25
Solar 2025	-	-	-	-	-	-	-	-	-	-	-	-	25	25	25	25	25	25	25
Solar Partnership Program	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Southampton	46	70	74	88	90	90	90	90	90	88	88	88	88	88	88	88	88	88	93
Spruance Genco, Facility 1 (Richmond 1)	95	86	83	90	96	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	91	96	93	89	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	91	100	75	92	98	91	90	98	91	91	98	91	91	98	91	91	98	90	90
Surry 2	100	89	81	98	92	90	98	91	91	98	91	91	98	91	91	98	90	90	98
Virginia City Hybrid Energy Center	78	74	66	75	79	79	77	79	76	76	76	76	76	76	76	76	70	76	87
VOWTAP	-	-	-	-	-	-	-	-	42	42	42	42	42	42	42	42	42	42	42
Warren	-	-	61	83	87	82	87	87	82	87	83	88	88	76	87	83	88	88	90
Yorktown 1	78	67	79	84	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	81	72	84	87	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	58	28	35	59	77	70	77	77	77	-	-	-	-	-	-	-	-	-	-

Appendix 3D – Net Capacity Factor for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 9**

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	2013 (ACTUAL)	2014 (ACTUAL)	2015 (ACTUAL)	2016	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Altavista	45.1	50.2	60.1	78.4	87.7	87.7	87.7	87.7	89.6	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	93.3
Bath County Units 1-6	14.7	15.8	13.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden	72.2	61.3	67.0	75.6	64.1	60.9	38.8	30.9	33.1	55.5	54.0	55.7	56.9	57.7	58.7	56.2	58.7	47.3	56.6
Bellemeade	12.7	10.8	53.2	20.2	20.9	33.1	21.7	16.0	15.1	16.9	18.9	17.1	18.7	29.4	23.7	26.7	28.7	16.1	18.2
Bremo 3	9.7	30.5	6.5	3.7	1.9	1.4	0.8	0.7	0.9	2.6	1.9	2.2	2.6	3.3	3.2	3.6	4.2	1.9	2.4
Bremo 4	30.9	12.8	12.7	28.5	18.8	10.3	4.5	4.4	4.5	8.9	7.3	7.9	8.1	14.1	10.0	11.9	12.5	6.9	7.7
Brunswick	-	-	-	56.1	76.0	87.9	81.6	61.3	65.8	69.6	73.4	68.3	72.3	65.6	75.7	81.2	75.0	68.5	71.6
Chesapeake CT 1, 2, 4, 6	0.1	0.2	0.2	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	7.1	12.8	12.6	26.5	25.7	42.5	31.1	42.0	42.3	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	36.6	67.7	23.4	42.8	52.6	64.1	67.9	65.4	63.5	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	57.8	63.8	69.8	57.6	74.1	79.7	80.7	82.2	82.8	51.2	54.8	53.7	52.9	57.3	55.4	55.0	57.7	53.7	55.3
Chesterfield 6	63.3	59.1	69.8	65.8	68.7	82.3	85.5	74.5	86.9	58.1	47.8	56.4	57.9	49.8	56.2	59.1	49.2	56.3	55.5
Chesterfield 7	86.5	78.4	94.7	49.5	70.5	95.8	102.3	86.1	91.9	69.4	75.0	76.8	83.7	82.2	86.0	73.3	92.3	67.9	75.7
Chesterfield 8	92.8	82.3	96.4	63.1	103.3	95.4	99.7	84.7	90.0	80.4	85.9	88.8	90.5	92.0	94.6	90.0	99.9	76.5	82.2
Clover 1	80.3	80.5	65.3	78.1	86.1	88.9	88.3	93.0	91.7	53.9	54.1	50.6	54.2	57.9	52.8	59.3	57.9	50.0	50.0
Clover 2	75.1	67.3	77.5	79.6	78.0	92.3	89.9	85.5	83.0	51.8	49.4	53.9	53.0	53.0	56.9	57.3	52.8	53.1	53.5
Cushaw Hydro	78.9	70.7	50.8	49.6	49.7	49.7	49.7	49.6	49.7	49.7	49.7	49.6	49.7	49.7	49.7	49.6	49.7	49.7	49.7
Darbytown 1	5.7	1.6	4.2	6.2	2.8	2.0	0.9	0.9	0.9	2.3	1.9	2.0	2.3	3.1	2.8	3.2	3.5	2.1	2.5
Darbytown 2	4.8	1.6	3.1	7.3	3.3	2.7	1.2	1.2	1.1	2.6	2.3	2.4	2.6	3.9	3.3	3.8	4.1	2.4	2.8
Darbytown 3	5.7	1.7	5.2	6.8	3.1	2.4	1.1	1.0	1.0	2.5	2.1	2.2	2.5	3.6	3.1	3.5	3.8	2.2	2.7
Darbytown 4	6.4	1.6	5.9	5.8	2.4	1.8	0.8	0.8	0.8	2.1	1.7	1.8	2.1	2.6	2.5	2.9	3.1	1.9	2.3
Doswell Complex	54.2	61.8	71.2	100.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	1.7	1.6	7.2	1.8	1.3	4.0	1.9	1.6	1.6	3.3	2.7	2.8	3.1	4.2	3.9	4.4	4.7	2.8	3.3
Elizabeth River 2	1.9	1.2	6.1	1.4	1.0	3.1	1.5	1.3	1.2	3.0	2.4	2.5	2.8	3.6	3.5	3.9	4.3	2.5	3.0
Elizabeth River 3	1.1	0.8	0.9	1.3	1.2	3.5	1.7	1.5	1.3	2.9	2.3	2.3	2.7	3.4	3.4	3.8	4.1	2.4	2.9
Existing NC Solar NUGs	-	-	-	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1
Gaston Hydro	15.6	16.1	16.4	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
Generic 3x1 CC 2022	-	-	-	-	-	-	-	-	-	87.5	87.2	88.2	87.8	88.7	88.6	89.3	88.8	87.3	86.0
Generic 3x1 CC 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87.6	87.6
Generic 3x1 CC 2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	11.0	11.8	12.6	19.7	15.4	17.7	18.9	10.0	11.2
Generic CT 2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	48.1	21.7	57.8	35.7	43.1	48.7	34.1	13.9	11.3	17.4	22.0	20.5	23.4	33.4	29.1	31.0	36.0	17.9	19.9
Gordonsville 2	48.1	44.3	61.7	41.7	33.0	41.7	32.1	9.9	8.5	15.2	18.9	18.7	20.9	23.6	25.9	30.9	31.4	17.2	18.4
Gravel Neck 1-2	0.0	0.1	0.0	0.001	0.00005	0.005	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	1.3	1.3	1.1	1.1	0.9	1.5	1.1	0.7	0.6	1.8	1.5	1.5	1.8	2.2	2.2	2.5	2.7	1.6	2.0
Gravel Neck 4	4.6	2.2	4.5	1.2	1.0	2.0	1.3	0.8	0.7	2.0	1.6	1.7	1.9	2.4	2.4	2.7	2.9	1.8	2.1
Gravel Neck 5	4.0	2.1	3.6	0.2	0.2	0.2	0.1	0.1	0.1	0.9	0.7	0.7	0.8	1.0	1.0	1.2	1.3	0.8	1.0
Gravel Neck 6	1.6	1.5	3.0	0.2	0.1	0.2	0.1	0.1	0.1	0.8	0.6	0.7	0.8	1.0	1.0	1.1	1.2	0.8	0.9
Greensville	-	-	-	-	-	-	80.5	84.9	90.3	84.4	86.4	87.4	86.3	89.6	89.1	89.1	90.0	83.4	81.8
Hopewell	21.8	58.2	58.8	87.7	87.7	89.6	89.6	89.6	89.6	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	91.7
Ladysmith 1	10.2	14.2	4.1	15.3	71.3	34.4	9.0	8.1	8.2	11.3	12.0	13.6	14.9	23.5	18.4	21.5	22.2	12.6	12.6
Ladysmith 2	9.2	12.8	3.3	9.4	55.9	27.8	8.9	8.0	7.7	10.3	10.9	11.6	11.7	19.2	14.5	16.9	17.8	10.5	11.0
Ladysmith 3	10.8	7.8	10.1	12.9	52.7	24.8	12.6	11.1	11.1	13.7	14.5	15.2	14.9	22.4	18.0	21.0	21.9	12.8	14.1
Ladysmith 4	14.2	9.7	9.4	10.8	51.1	23.4	10.6	9.0	9.0	11.8	12.3	12.9	12.8	20.3	15.6	18.9	19.0	11.1	12.3
Ladysmith 5	12.9	10.7	5.3	11.1	51.9	27.0	11.4	9.8	9.7	12.3	13.2	13.7	13.5	20.9	16.3	19.1	20.2	11.8	12.6
Lowmoor CT 1-4	0.1	0.5	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	30.3	39.3	28.0	23.4	20.0	23.5	8.1	17.9	20.5	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	31.0	36.0	27.6	22.6	19.1	21.9	7.7	16.9	18.8	-	-	-	-	-	-	-	-	-	-

Appendix 3D cont. – Net Capacity Factor for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 9**

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Mount Storm 1	63.4	76.2	70.3	68.3	43.2	58.5	51.2	91.6	88.9	43.2	43.1	48.1	44.3	41.7	46.2	42.0	39.1	40.3	37.9
Mount Storm 2	66.7	59.9	65.9	69.0	48.1	54.6	57.5	88.2	79.5	42.3	39.7	42.5	40.8	38.8	40.9	38.7	36.1	37.1	37.2
Mount Storm 3	64.6	70.7	70.9	49.4	36.0	51.1	42.4	84.1	87.3	40.7	36.6	40.8	39.1	35.5	39.3	37.0	33.5	35.4	35.4
Mount Storm CT	0.2	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	92.6	99.9	93.8	90.8	99.5	90.4	93.8	100.0	91.7	92.2	99.8	92.3	91.9	99.8	92.0	92.5	99.5	92.0	92.2
North Anna 2	88.6	92.0	102.6	90.6	90.2	99.7	90.3	92.3	99.4	92.0	92.1	99.9	91.7	92.1	99.7	92.2	91.8	99.7	91.9
North Anna Hydro	-	-	41.4	24.3	24.4	24.4	24.4	24.3	24.4	24.4	24.4	24.3	24.4	24.4	24.4	24.3	24.4	24.4	24.4
Northern Neck CT 1-4	0.1	0.3	0.0	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	50.8	44.3	36.8	8.4	17.9	29.3	44.5	63.1	81.7	66.1	67.8	66.4	67.4	77.7	82.7	90.4	90.7	84.2	86.6
Possum Point 3	3.9	1.0	1.3	3.1	1.8	1.6	0.9	0.8	2.0	4.5	3.5	3.9	4.3	6.1	5.4	6.0	7.0	3.4	4.3
Possum Point 4	5.9	2.2	1.4	4.4	2.8	2.4	1.1	1.4	2.2	5.1	4.2	4.4	5.0	7.0	6.2	7.3	7.8	4.1	4.7
Possum Point 5	0.5	2.8	3.5	0.4	0.3	0.3	0.2	0.2	0.2	1.5	1.2	1.2	1.6	1.8	1.8	2.1	2.4	1.3	1.5
Possum Point 6	74.0	69.5	66.4	63.4	74.2	76.5	43.8	41.8	47.0	40.0	50.4	50.0	57.7	53.3	68.4	73.8	75.0	45.7	48.7
Possum Point CT 1-6	0.1	0.6	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	12.3	8.9	18.4	34.2	19.0	10.0	4.8	4.8	5.3	9.7	7.9	8.5	9.3	13.8	11.2	12.8	14.1	7.3	8.3
Remington 2	11.0	8.4	16.6	31.9	15.5	7.6	3.8	3.6	4.3	8.7	7.0	7.6	8.7	11.7	10.8	12.4	13.3	6.5	7.4
Remington 3	10.2	8.3	15.7	28.1	17.4	8.4	4.0	4.0	4.5	8.5	7.0	7.5	8.3	12.4	10.5	12.3	12.7	6.7	7.6
Remington 4	11.0	8.1	16.5	33.3	16.2	7.9	3.9	4.0	4.4	8.9	7.1	7.8	8.8	12.1	10.6	12.3	13.2	6.8	7.8
Roanoke Rapids Hydro	36.3	35.8	34.9	30.3	30.4	30.4	30.4	30.3	30.4	30.4	30.4	30.3	30.4	30.4	30.4	30.3	30.4	30.4	30.4
Roanoke Valley II	87.5	22.0	6.1	90.2	89.9	90.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	84.2	40.8	12.8	87.8	87.5	87.8	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	5.3	4.6	7.8	3.4	2.0	5.6	2.5	2.0	2.3	5.5	4.2	5.0	5.6	8.8	6.7	8.3	8.2	4.9	5.3
SEI Birchwood	28.5	40.8	27.2	35.9	37.0	44.6	31.4	40.9	34.3	-	-	-	-	-	-	-	-	-	-
Solar 2020	-	-	-	-	-	-	-	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar 2021	-	-	-	-	-	-	-	-	25.0	25.1	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar 2022	-	-	-	-	-	-	-	-	-	25.1	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar 2023	-	-	-	-	-	-	-	-	-	-	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar 2024	-	-	-	-	-	-	-	-	-	-	-	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar 2025	-	-	-	-	-	-	-	-	-	-	-	-	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Solar Partnership Program	-	-	-	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Southampton	15.8	55.3	65.0	87.7	89.6	89.6	89.6	89.6	89.6	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	93.3
Spruance Genco, Facility 1 (Richmond 1)	11.8	12.8	10.5	41.3	28.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	13.1	15.9	11.4	46.9	30.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	93.1	103.1	77.2	94.0	100.2	93.2	91.7	100.2	92.6	92.3	100.2	92.7	92.3	100.2	92.6	92.3	100.2	92.6	92.3
Surry 2	103.1	92.1	83.4	100.2	94.3	91.2	100.2	92.7	92.3	100.2	92.6	92.3	100.2	92.6	92.3	100.2	92.6	92.3	100.2
VA Solar	-	-	-	-	25.0	25.1	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1	25.2	25.0	25.1	25.1
Virginia City Hybrid Energy Center	68.7	66.6	55.5	52.1	57.3	63.8	63.1	64.6	64.6	52.6	56.1	52.5	52.6	56.3	52.6	53.1	53.9	52.2	57.6
VOWTAP	-	-	-	-	-	-	-	-	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5
Warren	-	-	54.7	58.3	55.2	54.6	49.5	41.0	40.7	61.7	56.6	63.6	64.1	56.2	63.3	62.7	70.2	61.6	62.7
Yorktown 1	26.5	30.6	10.5	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	32.1	33.5	8.0	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	1.3	2.3	4.4	0.8	0.5	0.6	0.4	0.4	0.4	-	-	-	-	-	-	-	-	-	-

Appendix 3E – Heat Rates for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 10a**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Altavista	15.49	15.66	14.26	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Bath County Units 1-6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden	7.02	7.14	7.12	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18
Bellemeade	8.34	8.98	8.62	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
Bremo 3	13.00	12.16	12.06	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Bremo 4	10.76	10.60	10.59	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73	10.73
Brunswick	-	-	-	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
Chesapeake CT 1, 2, 4, 6	20.42	15.32	16.98	18.54	18.54	18.54	18.54	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	12.33	12.01	12.45	11.95	11.95	11.95	11.95	11.95	11.95	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	10.56	10.61	10.52	10.52	10.52	10.52	10.52	10.52	10.52	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	10.08	10.18	10.16	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20
Chesterfield 6	9.90	10.02	9.98	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
Chesterfield 7	7.53	7.53	7.40	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
Chesterfield 8	7.32	7.16	7.23	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45
Clover 1	9.98	10.04	9.99	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Clover 2	10.01	9.99	10.00	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92
Cushaw Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Darbytown 1	12.48	12.24	12.54	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 2	13.07	12.36	12.56	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 3	12.37	12.30	12.51	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 4	12.56	12.23	12.58	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Doswell Complex	10.00	10.00	10.00	8.55	8.55	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	12.63	11.89	11.69	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Elizabeth River 2	12.61	11.91	11.72	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Elizabeth River 3	12.46	11.39	11.23	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Existing NC Solar NUGs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gaston Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Generic 3x1 CC 2022	-	-	-	-	-	-	-	-	-	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55
Generic 3x1 CC 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.55	6.55
Generic 3x1 CC 2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	8.68	8.68	8.68	8.68	8.68	8.68	8.68	8.68	8.68
Generic CT 2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	8.39	8.57	8.47	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52
Gordonsville 2	8.41	8.43	8.45	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52
Gravel Neck 1-2	17.17	17.12	20.17	17.40	17.40	17.40	17.40	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	12.65	12.47	12.79	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 4	12.77	12.50	12.82	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 5	13.40	12.78	13.22	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 6	12.99	12.31	12.55	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Greensville	-	-	-	-	-	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62
Hopewell	14.91	16.00	15.75	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Ladysmith 1	10.61	10.59	10.09	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51
Ladysmith 2	10.33	10.32	9.86	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46
Ladysmith 3	10.50	10.61	9.94	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51
Ladysmith 4	10.42	10.48	9.86	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51
Ladysmith 5	10.44	10.48	9.90	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51
Lowmoor CT 1-4	17.19	15.65	17.83	16.76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	12.12	12.11	11.89	11.52	11.52	11.52	11.52	11.52	11.52	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	12.37	12.20	12.20	11.67	11.67	11.67	11.67	11.67	11.67	-	-	-	-	-	-	-	-	-	-

Appendix 3E cont. – Heat Rates for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 10a**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Mount Storm 1	9.84	9.84	9.99	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79
Mount Storm 2	9.79	9.94	9.93	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81	9.81
Mount Storm 3	10.24	10.40	10.42	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27
Mount Storm CT	15.97	14.88	21.83	20.36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60
North Anna 2	-	-	-	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64
North Anna Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Northern Neck CT 1-4	17.17	15.84	18.19	16.83	16.83	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	15.77	16.59	15.98	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47
Possum Point 3	11.39	12.26	12.21	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09	11.09
Possum Point 4	11.32	12.17	12.96	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78	10.78
Possum Point 5	10.86	10.25	10.26	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77	10.77
Possum Point 6	7.18	7.34	7.19	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
Possum Point CT 1-6	16.64	15.11	17.04	16.76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	10.62	10.54	9.97	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71
Remington 2	10.70	10.81	10.17	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70
Remington 3	10.78	10.71	10.30	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71
Remington 4	10.67	10.66	10.12	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70	10.70
Roanoke Rapids Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Roanoke Valley II	10.00	10.00	10.00	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	10.00	10.00	10.00	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	9.64	9.45	9.55	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76
Scott Timber Solar Project	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SEI Birchwood	10.00	10.00	10.00	9.61	9.61	9.61	9.61	9.61	9.61	-	-	-	-	-	-	-	-	-	-
Solar 2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2022	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2023	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar Partnership Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Southampton	16.39	15.90	15.16	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Spruance Genco, Facility 1 (Richmond 1)	10.00	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	10.00	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
Surry 2	-	-	-	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
VA Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Virginia City Hybrid Energy Center	10.22	9.74	9.96	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41
VOWTAP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Warren	-	-	6.77	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.94
Yorktown 1	10.72	10.60	10.70	10.58	10.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	10.16	10.44	10.66	10.23	10.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	10.48	10.43	10.79	10.64	10.64	10.64	10.64	10.64	10.64	-	-	-	-	-	-	-	-	-	-

Appendix 3E cont. – Heat Rates for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 10b**
UNIT PERFORMANCE DATA
Average Heat Rate - (mmBtu/MWh) (At Minimum)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Altavista	N/A	N/A	N/A	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Bath County Units 1-6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden	N/A	N/A	N/A	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56
Bellemeade	N/A	N/A	N/A	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51
Bremo 3	N/A	N/A	N/A	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50
Bremo 4	N/A	N/A	N/A	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87
Brunswick	N/A	N/A	N/A	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91
Chesapeake CT 1, 2, 4, 6	N/A	N/A	N/A	18.54	18.54	18.54	18.54	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	N/A	N/A	N/A	14.22	14.22	14.22	14.22	14.22	14.22	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	N/A	N/A	N/A	11.31	11.31	11.31	11.31	11.31	11.31	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	N/A	N/A	N/A	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54	11.54
Chesterfield 6	N/A	N/A	N/A	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
Chesterfield 7	N/A	N/A	N/A	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31	9.31
Chesterfield 8	N/A	N/A	N/A	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27	9.27
Clover 1	N/A	N/A	N/A	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70
Clover 2	N/A	N/A	N/A	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53	11.53
Cushaw Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Darbytown 1	N/A	N/A	N/A	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 2	N/A	N/A	N/A	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 3	N/A	N/A	N/A	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Darbytown 4	N/A	N/A	N/A	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Doswell Complex	N/A	N/A	N/A	8.55	8.55	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	N/A	N/A	N/A	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Elizabeth River 2	N/A	N/A	N/A	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Elizabeth River 3	N/A	N/A	N/A	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Existing NC Solar NUGs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gaston Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Generic 3x1 CC 2022	N/A	N/A	N/A	-	-	-	-	-	-	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07
Generic 3x1 CC 2030	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.07	7.07
Generic 3x1 CC 2035	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2023	N/A	N/A	N/A	-	-	-	-	-	-	-	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24
Generic CT 2036	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2037	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2039	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2041	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	N/A	N/A	N/A	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52	8.52
Gordonsville 2	N/A	N/A	N/A	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
Gravel Neck 1-2	N/A	N/A	N/A	17.40	17.40	17.40	17.40	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	N/A	N/A	N/A	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 4	N/A	N/A	N/A	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 5	N/A	N/A	N/A	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Gravel Neck 6	N/A	N/A	N/A	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32
Greensville	N/A	N/A	N/A	-	-	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.69
Hopewell	N/A	N/A	N/A	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44	13.44
Ladysmith 1	N/A	N/A	N/A	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09
Ladysmith 2	N/A	N/A	N/A	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Ladysmith 3	N/A	N/A	N/A	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12.08
Ladysmith 4	N/A	N/A	N/A	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09
Ladysmith 5	N/A	N/A	N/A	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09
Lowmoor CT 1-4	N/A	N/A	N/A	16.76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	N/A	N/A	N/A	13.39	13.39	13.39	13.39	13.39	13.39	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	N/A	N/A	N/A	13.55	13.55	13.55	13.55	13.55	13.55	-	-	-	-	-	-	-	-	-	-

Appendix 3E cont. – Heat Rates for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 10b**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Minimum)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Mount Storm 1	N/A	N/A	N/A	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
Mount Storm 2	N/A	N/A	N/A	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47
Mount Storm 3	N/A	N/A	N/A	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65
Mount Storm CT	N/A	N/A	N/A	20.36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	N/A	N/A	N/A	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60
North Anna 2	N/A	N/A	N/A	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64
North Anna Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Northern Neck CT 1-4	N/A	N/A	N/A	16.83	16.83	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	N/A	N/A	N/A	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47	15.47
Possum Point 3	N/A	N/A	N/A	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46	12.46
Possum Point 4	N/A	N/A	N/A	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11
Possum Point 5	N/A	N/A	N/A	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92
Possum Point 6	N/A	N/A	N/A	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11
Possum Point CT 1-6	N/A	N/A	N/A	16.76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	N/A	N/A	N/A	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39	12.39
Remington 2	N/A	N/A	N/A	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43	12.43
Remington 3	N/A	N/A	N/A	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40
Remington 4	N/A	N/A	N/A	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41
Roanoke Rapids Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Roanoke Valley II	N/A	N/A	N/A	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	N/A	N/A	N/A	10.00	10.00	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	N/A	N/A	N/A	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61	9.61
SEI Birchwood	N/A	N/A	N/A	11.73	11.73	11.73	11.73	11.73	11.73	-	-	-	-	-	-	-	-	-	-
Solar 2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2022	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2023	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar 2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar Partnership Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Southampton	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Spruance Genco, Facility 1 (Richmond 1)	N/A	N/A	N/A	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	N/A	N/A	N/A	10.00	10.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	N/A	N/A	N/A	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
Surry 2	N/A	N/A	N/A	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
VA Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Virginia City Hybrid Energy Center	N/A	N/A	N/A	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76	9.76
VOWTAP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Warren	N/A	N/A	N/A	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76	7.76
Yorktown 1	N/A	N/A	N/A	12.25	12.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	N/A	N/A	N/A	11.12	11.12	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	N/A	N/A	N/A	11.49	11.49	11.49	11.49	11.49	11.49	-	-	-	-	-	-	-	-	-	-

Appendix 3F – Existing Capacity for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 7**

CAPACITY DATA

	(ACTUAL)				(PROJECTED)														
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
I. Installed Capacity (MW)[(1)]																			
a. Nuclear	3,362	3,348	3,357	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349
b. Coal	5,373	4,406	4,400	4,372	4,043	4,037	4,030	4,024	4,021	3,622	3,622	3,622	3,622	3,622	3,622	3,622	3,622	3,622	3,622
c. Heavy Fuel Oil	1,575	1,575	1,575	1,576	1,576	1,576	1,576	1,576	1,576	786	786	786	786	786	786	786	786	786	786
d. Light Fuel Oil	596	596	596	257	79	79	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	316	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543
f. Natural Gas-Combined Cycle	2,187	2,077	3,543	4,920	4,946	4,946	6,531	6,531	6,531	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	9,714	9,714
g. Natural Gas-Turbine	2,053	3,538	2,052	2,415	2,415	2,415	2,415	2,415	2,415	2,415	2,873	2,873	2,873	2,873	2,873	2,873	2,873	2,873	2,873
h. Hydro-Conventional	317	317	317	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318
i. Pumped Storage	1,802	1,802	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
j. Renewable	83	237	236	272	278	299	324	353	418	480	552	633	717	797	854	906	950	985	1,017
k. Total Company Installed	17,665	18,439	18,428	19,829	19,354	19,369	20,894	20,917	20,979	21,444	21,973	22,054	22,138	22,218	22,275	22,328	22,372	23,998	24,030
l. Other (NUG)	1,787	1,749	1,775	1,277	714	569	400	426	458	259	283	301	314	327	332	344	346	350	348
n. Total	19,451	20,327	20,203	21,107	20,068	19,938	21,294	21,343	21,438	21,703	22,256	22,355	22,452	22,545	22,607	22,671	22,718	24,348	24,378
II. Installed Capacity Mix (%)[(2)]																			
a. Nuclear	17.3%	16.5%	16.6%	15.9%	16.7%	16.8%	15.7%	15.7%	15.6%	15.4%	15.0%	15.0%	14.9%	14.9%	14.8%	14.8%	14.7%	13.8%	13.7%
b. Coal	27.6%	21.7%	21.8%	20.7%	20.1%	20.2%	18.9%	18.9%	18.8%	16.7%	16.3%	16.2%	16.1%	16.1%	16.0%	16.0%	15.9%	14.9%	14.9%
c. Heavy Fuel Oil	8.1%	7.7%	7.8%	7.5%	7.9%	7.9%	7.4%	7.4%	7.4%	3.6%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.2%	3.2%
d. Light Fuel Oil	3.1%	2.9%	3.0%	1.2%	0.4%	0.4%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	1.6%	2.7%	2.7%	2.6%	2.7%	2.7%	2.5%	2.5%	2.5%	2.5%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.2%	2.2%
f. Natural Gas-Combined Cycle	11.2%	10.2%	17.5%	23.3%	24.6%	24.8%	30.7%	30.6%	30.5%	37.4%	36.5%	36.3%	36.2%	36.0%	35.9%	35.8%	35.8%	39.9%	39.8%
g. Natural Gas-Turbine	10.6%	17.4%	10.2%	11.4%	12.0%	12.1%	11.3%	11.3%	11.3%	11.1%	12.9%	12.9%	12.8%	12.7%	12.7%	12.7%	12.6%	11.8%	11.8%
h. Hydro-Conventional	1.6%	1.6%	1.6%	1.5%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.3%
i. Pumped Storage	9.3%	8.9%	9.0%	8.6%	9.0%	9.1%	8.5%	8.5%	8.4%	8.3%	8.1%	8.1%	8.1%	8.0%	8.0%	8.0%	8.0%	7.4%	7.4%
j. Renewable	0.4%	1.2%	1.2%	1.3%	1.4%	1.5%	1.5%	1.7%	1.9%	2.2%	2.5%	2.8%	3.2%	3.5%	3.8%	4.0%	4.2%	4.0%	4.2%
k. Total Company Installed	90.8%	90.7%	91.2%	93.9%	96.4%	97.1%	98.1%	98.0%	97.9%	98.8%	98.7%	98.7%	98.6%	98.5%	98.5%	98.5%	98.5%	98.6%	98.6%
l. Other (NUG)	9.2%	8.6%	8.8%	6.1%	3.6%	2.9%	1.9%	2.0%	2.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%
n. Total	100.0%	99.3%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Net dependable installed capability during peak season.

(2) Each item in Section I as a percent of line n (Total).

Appendix 3G – Energy Generation by Type for Plan B: Intensity-Based Dual Rate (GWh)

Company Name: Virginia Electric and Power Company **Schedule 2**

GENERATION

	(ACTUAL)				(PROJECTED)														
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
I. System Output (GWh)																			
a. Nuclear	27,669	28,378	26,173	27,617	28,203	27,457	27,575	28,287	27,615	27,617	28,207	27,699	27,618	28,207	27,618	27,696	28,207	27,618	27,614
b. Coal	24,863	25,293	22,618	21,323	19,554	23,193	22,437	27,419	27,728	15,482	14,790	15,686	15,493	14,971	15,584	15,487	14,515	14,747	14,902
c. Heavy Fuel Oil	119	355	542	83	55	66	43	37	45	102	81	85	112	121	126	148	163	87	104
d. Light Fuel Oil	45	408	319.3	3	1	1	0.1	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	146	415	252.9	525	338	208	94	98	127	274	223	240	261	400	322	377	407	214	247
f. Natural Gas-Combined Cycle	11,715	11,221	18,482	23,953	27,104	30,205	35,757	31,334	33,168	47,909	48,744	49,346	50,487	49,453	52,158	52,852	53,952	59,550	60,634
g. Natural Gas-Turbine	1,640	1,124	1,606	2,780	4,926	2,532	1,045	936	959	1,496	1,859	1,982	2,106	3,173	2,574	2,986	3,161	1,750	1,937
h. Hydro-Conventional	1,025	1,035	1,039	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521
i. Hydro-Pumped Storage	2,421	2,493	2,217	936	1,224	1,404	926	1,191	1,257	997	1,020	1,080	1,161	1,624	1,429	1,620	1,763	1,207	1,347
j. Renewable(1)	666	1,128	1,191	1,366	1,741	2,063	2,378	3,215	3,841	4,070	4,531	4,942	5,142	5,221	5,222	5,278	5,256	5,184	5,283
k. Total Generation	70,308	71,849	74,440	79,109	83,666	87,650	90,776	93,037	95,261	98,469	99,974	101,581	102,902	103,690	105,554	106,965	107,945	110,878	112,589
l. Purchased Power	17,561	16,193	14,657	9,504	5,946	3,787	2,068	2,147	1,629	779	958	864	927	1,558	1,041	1,114	1,455	804	783
m. Total Payback Energy(2)	-	-	-	7	9	11	9	11	10	10	9	9	9	10	10	11	11	10	10
n. Less Pumping Energy	-3,015	-3,126	-2,800	-1,176	-1,537	-1,764	-1,163	-1,496	-1,579	-1,252	-1,281	-1,357	-1,459	-2,040	-1,795	-2,035	-2,215	-1,517	-1,692
o. Less Other Sales(3)	-1,166	-904	-1,716	-2,739	-2,663	-2,924	-3,477	-3,801	-3,841	-4,844	-4,912	-4,907	-4,799	-4,231	-4,418	-4,275	-4,009	-5,577	-5,517
p. Total System Firm Energy Req.	83,688	84,011	84,581	84,697	85,413	86,749	88,204	89,887	91,470	93,152	94,739	96,180	97,571	98,978	100,382	101,769	103,176	104,588	106,162
II. Energy Supplied by Competitive Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Include current estimates for renewable energy generation by VCHEC.

(2) Payback Energy is accounted for in Total Generation.

(3) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

Appendix 3H – Energy Generation by Type for Plan B: Intensity-Based Dual Rate (%)

Company Name: Virginia Electric and Power Company **Schedule 3**

GENERATION

	(ACTUAL)			(PROJECTED)															
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
III. System Output Mix (%)																			
a. Nuclear	33.1%	33.8%	30.9%	32.6%	33.0%	31.7%	31.3%	31.5%	30.2%	29.6%	29.8%	28.8%	28.3%	28.5%	27.5%	27.2%	27.3%	26.4%	26.0%
b. Coal	29.7%	30.1%	26.7%	25.2%	22.9%	26.7%	25.4%	30.5%	30.3%	16.6%	15.6%	16.3%	15.9%	15.1%	15.5%	15.2%	14.1%	14.1%	14.0%
c. Heavy Fuel Oil	0.1%	0.4%	0.6%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
d. Light Fuel Oil	0.1%	0.5%	0.4%	0.003%	0.001%	0.001%	0.0001%	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	0.2%	0.5%	0.3%	0.6%	0.4%	0.2%	0.1%	0.1%	0.1%	0.3%	0.2%	0.2%	0.3%	0.4%	0.3%	0.4%	0.4%	0.2%	0.2%
f. Natural Gas-Combined Cycle	14.0%	13.4%	21.9%	28.3%	31.7%	34.8%	40.5%	34.9%	36.3%	51.4%	51.5%	51.3%	51.7%	50.0%	52.0%	51.9%	52.3%	56.9%	57.1%
g. Natural Gas-Turbine	2.0%	1.3%	1.9%	3.3%	5.8%	2.9%	1.2%	1.0%	1.0%	1.6%	2.0%	2.1%	2.2%	3.2%	2.6%	2.9%	3.1%	1.7%	1.8%
h. Hydro-Conventional	1.2%	1.2%	1.2%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
i. Hydro-Pumped Storage	2.9%	3.0%	2.6%	1.1%	1.4%	1.6%	1.0%	1.3%	1.4%	1.1%	1.1%	1.1%	1.2%	1.6%	1.4%	1.6%	1.7%	1.2%	1.3%
j. Renewable Resources	0.8%	1.3%	1.4%	1.6%	2.0%	2.4%	2.7%	3.6%	4.2%	4.4%	4.8%	5.1%	5.3%	5.3%	5.2%	5.2%	5.1%	5.0%	5.0%
k. Total Generation	84.0%	85.5%	88.0%	93.4%	98.0%	101.0%	102.9%	103.5%	104.1%	105.7%	105.5%	105.6%	105.5%	104.8%	105.2%	105.1%	104.6%	106.0%	106.1%
l. Purchased Power	21.0%	19.3%	17.3%	11.2%	7.0%	4.4%	2.3%	2.4%	1.8%	0.8%	1.0%	0.9%	0.9%	1.6%	1.0%	1.1%	1.4%	0.8%	0.7%
m. Direct Load Control (DLC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Less Pumping Energy	-3.6%	-3.7%	-3.3%	-1.4%	-1.8%	-2.0%	-1.3%	-1.7%	-1.7%	-1.3%	-1.4%	-1.4%	-1.5%	-2.1%	-1.8%	-2.0%	-2.1%	-1.5%	-1.6%
o. Less Other Sales(1)	-1.4%	-1.1%	-2.0%	-3.2%	-3.1%	-3.4%	-3.9%	-4.2%	-4.2%	-5.2%	-5.2%	-5.1%	-4.9%	-4.3%	-4.4%	-4.2%	-3.9%	-5.3%	-5.2%
p. Total System Output	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	57.5%	58.5%	58.4%	57.0%	57.6%	57.2%	57.2%	55.2%	55.0%	55.3%	55.5%	55.3%	55.4%	55.6%	55.7%	56.2%	56.3%	56.0%	56.0%

(1) Economy energy.

Appendix 3I – Planned Changes to Existing Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 13a**

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

	(ACTUAL)			(PROJECTED)															
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Altavista	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County Units 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Covanta Fairfax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Doswell Complex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edgecombe Genco (Rocky Mountain)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing NC Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing VA Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic 3x1 CC 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic 3x1 CC 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic 3x1 CC 2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic CT 2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greensville	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell Cogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-)

Appendix 3I cont. – Planned Changes to Existing Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Sch**

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)													
Unit Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Mount Storm 1	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	-	-	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 1 (Richmond 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VA Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City Hybrid Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VOWTAP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-)

Appendix 3I cont. – Planned Changes to Existing Generation Units for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 13b**

UNIT PERFORMANCE DATA[1]

Planned Changes to Existing Generation Units

Station / Unit Name	Uprate/Derate Description	Expected Removal Date	Expected Return Date	Base Rating	Revised Rating	MW
Possum Point 5	SNCR	Dec-17	Jan-18	786	786	-
Bear Garden	GT Upgrade	Apr-17	Apr-17	590	616	26

(1) Peak net dependable capability as of this filing.

Appendix 3J – Potential Unit Retirements for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 19**

UNIT PERFORMANCE DATA

Planned Unit Retirements[(1)]

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Yorktown 1	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2017**	**159**	**162**
Yorktown 2	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2017**	**164**	**165**
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**15**	**20**
Chesapeake GT1					15	
Chesapeake CT 2	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**36**	**49**
Chesapeake GT2					12	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	**Surry, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**28**	**38**
Gravel Neck GT1					12	
Gravel Neck GT2					16	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**11**	**12**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**47**	**63**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Possum Point CT	**Dumfries, VA**	**Steam-Cycle**	**Light Fuel Oil**	**2019**	**72**	**106**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	
Chesterfield 3[2]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2022**	**98**	**102**
Chesterfield 4[2]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2022**	**163**	**168**
Chesterfield 5[3]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2022**	**336**	**342**
Chesterfield 6[3]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2022**	**670**	**690**
Clover 1[3]	**Clover, VA**	**Steam-Cycle**	**Coal**	**2022**	**220**	**222**
Clover 2[3]	**Clover, VA**	**Steam-Cycle**	**Coal**	**2022**	**219**	**219**
Mecklenburg 1[2]	**Clarksville, VA**	**Steam-Cycle**	**Coal**	**2022**	**69**	**69**
Mecklenburg 2[2]	**Clarksville, VA**	**Steam-Cycle**	**Coal**	**2022**	**69**	**69**
Yorktown 3[2]	**Yorktown, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2022**	**790**	**792**
Virginia City Hybrid Energy Center[3]	**Virginia City, VA**	**Steam-Cycle**	**Coal**	**2029**	**610**	**624**

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.

(2) The potential retirements of Chesterfield Units 3 and 4, Mecklenburg Units 1 and 2 and Yorktown 3 are modeled in all of the CPP-Compliant Alternative Plans.

(2) The potential retirements of Chesterfield Units 5 and 6, Clover Units 1 and 2 and VCHEC are modeled only in Plan E.

Appendix 3K – Generation under Construction for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer[3]	MW Nameplate
Under Construction						
Solar Partnership Program	Distributed	Intermittent	Solar	2016[2]	2	7
Greensville County Power Station	VA	Intermediate/Baseload	Natural Gas	Dec-2018	1,585	1,585

(1) Commercial Operation Date.

(2) Phase 1 to be completed by 2015; Phase 2 to be completed by 2016.

(3) Firm capacity.

Appendix 3L – Wholesale Power Sales Contracts for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 20**

WHOLESALE POWER SALES CONTRACTS

			(Actual)				(Projected)															
Entity	**Contract Length**	**Contract Type**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements(1)	7	11	12	8	9	9	9	9	9	9	9	10	10	10	10	10	10	10	6
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements(1)	9	10	11	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	13
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements(1)	338	328	309	345	338	338	345	361	367	376	386	402	407	417	429	446	451	463	397

(1) Full requirements contracts do not have a specific contracted capacity amount. MW are included in the Company's load forecast.

Appendix 3M – Description of Approved DSM Programs

Air Conditioner Cycling Program

Branded Name:	Smart Cooling Rewards
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak-Shaving
NC Program Type:	Peak-Shaving
VA Duration:	Ongoing
NC Duration:	Ongoing

Program Description:
This Program provides participants with an external radio frequency cycling switch that operates on central air conditioners and heat pump systems. Participants allow the Company to cycle their central air conditioning and heat pump systems during peak load periods. The cycling switch is installed by a contractor and located on or near the outdoor air conditioning unit(s). The Company remotely signals the unit when peak load periods are expected, and the air conditioning or heat pump system is cycled off and on for short intervals.

Program Marketing:
The Company uses business reply cards, online enrollment, and call center services.

Residential Low Income Program

Branded Name:	Income Qualifying Home Improvement Program
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Completed
NC Duration:	Completed

Program Description:
The Low Income Program provided an energy audit for residential customers who meet the low income criteria defined by state social service agencies. A certified technician performed an audit of participating residences to determine potential energy efficiency improvements. Specific energy efficiency measures applied envelope sealing, water heater temperature set point reduction, installation of insulation wrap around the water heater and pipes, installation of low flow shower head(s), replacement of incandescent lighting with efficient lighting, duct sealing, attic insulation, and air filter replacement.

Appendix 3M cont. – Description of Approved DSM Programs

Program Marketing:
The Company markets this Program using a neighborhood canvassing approach in prescreened areas targeting income qualifying customers. To ensure neighborhood security and program legitimacy, community posters, truck decals, yard signs, and authorization forms have been produced and are displayed in areas where the Program has current activity.

Non-Residential Distributed Generation Program

Branded Name:	Distributed Generation
State:	Virginia
Target Class:	Non-Residential
VA Program Type:	Demand-Side Management
VA Duration:	2012 – 2038

Program Description:
As part of this Program, a third-party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company at anytime for up to a total of 120 hours per year. The Company will supervise and implement the Non-Residential Distributed Generation Program through the third-party implementation contractor. Participating customers will receive an incentive in exchange for their agreement to reduce electrical load on the Company's system when called upon to do so by the Company. The incentive is based upon the amount of load curtailment delivered during control events. At least 80% of the program participation incentive is required to be passed through to the customer, with 100% of fuel and operations and maintenance compensation passed along to the customer. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions.

Program Marketing:
Marketing will be handled by the Company's implementation vendor.

Appendix 3M cont. – Description of Approved DSM Programs

Non-Residential Energy Audit Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

Program Description:
As part of this Program, an energy auditor will perform an on-site energy audit of a non-residential customer's facility. The customer will receive a report showing the projected energy and cost savings that could be anticipated from implementation of options identified during the audit. Once a qualifying customer provides documentation that some of the recommended energy efficiency improvements have been made at the customer's expense, a portion of the audit value will be refunded depending upon the measures installed.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Non-Residential Duct Testing and Sealing Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

Program Description:
This Program will promote testing and general repair of poorly performing duct and air distribution systems in non-residential facilities. The Program provides incentives to qualifying customers to have a contractor seal ducts in existing buildings using program-approved methods, including: aerosol sealant, mastic, or foil tape with an acrylic adhesive. Such systems include air handlers, air intake, return and supply plenums, and any connecting duct work.

Appendix 3M cont. – Description of Approved DSM Programs

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Residential Bundle Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

The Residential Bundle Program includes the four DSM programs described below.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Residential Home Energy Check-Up Program
Program Description:
The purpose of this Program is to provide owners and occupants of single family homes an easy and low cost home energy audit. It will include a walk through audit of customer homes, direct install measures, and recommendations for additional home energy improvements.

Residential Duct Sealing Program
Program Description:
This Program is designed to promote the testing and repair of poorly performing duct and air distribution systems. Qualifying customers will be provided an incentive to have a contractor test and seal ducts in their homes using methods approved for the Program, such as mastic material or foil tape with an acrylic adhesive to seal all joints and connections. The repairs are expected to reduce the average air leakage of a home's conditioned floor area to industry standards.

Residential Heat Pump Tune-Up Program
Program Description:
This Program provides qualifying customers with an incentive to have a contractor tune-up their existing heat pumps once every five years in order to achieve maximum operational performance. A properly tuned system should increase efficiency, reduce operating costs, and prevent premature equipment failures.

Appendix 3M cont. – Description of Approved DSM Programs

Residential Heat Pump Upgrade Program
Program Description:
This Program provides incentives for residential heat pump (e.g., air and geothermal) upgrades. Qualifying equipment must have better Seasonal Energy Efficiency Ratio and Heating Seasonal Performance Factor ratings than the current nationally mandated efficiency standards.

Non-Residential Heating and Cooling Efficiency Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing HVAC equipment to more efficient HVAC technologies that can produce verifiable savings.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Appendix 3M cont. – Description of Approved DSM Programs

Non-Residential Lighting Systems & Controls Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with an incentive to implement more efficient lighting technologies that can produce verifiable savings. The Program promotes the installation of lighting technologies including but not limited to efficient fluorescent bulbs, LED-based bulbs, and lighting control systems.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Non-Residential Window Film Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with an incentive to install solar reduction window film to lower their cooling bills and improve occupant comfort. Customers - can receive rebates for installing qualified solar reduction window film in non-residential facilities based on the Solar Heat Gain Coefficient ("SHGC") of window film installed.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Appendix 3M cont. – Description of Approved DSM Programs

Residential Appliance Recycling Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
VA Duration:	2015 – 2038

Program Description:
This program provides incentives to residential customers to recycle specific types of qualifying appliances. Appliance pick-up and proper recycling services are included.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events.

Income and Age Qualifying Home Improvement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2038
NC Duration:	2016 – 2038

Program Description:
This Program provides income and age-qualifying residential customers with energy assessments and direct install measures at no cost to the customer.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Appendix 3N – Approved Programs Non-Coincidental Peak Savings for Plan B: Intensity-Based Dual Rate (kW) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Air Conditioner Cycling Program	116,759	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	123,820	127,162	128,533	125,787	124,569	122,700	121,108
Residential Low Income Program	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,843	3,312	2,032	1,232	589	0	0	0
Residential Lighting Program	38,543	39,920	38,292	28,763	19,392	9,569	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,149	10,149	10,149	10,149	9,191	6,845	2,419	87	68	0	0	0	0	0	0	0
Commercial HVAC Upgrade	670	670	670	670	670	670	670	670	670	589	444	173	0	0	0	0
Non-Residential Energy Audit Program	11,652	14,565	15,228	15,367	14,850	13,656	10,030	10,095	10,161	11,230	10,126	10,355	10,417	10,479	10,539	10,599
Non-Residential Duct Testing and Sealing Program	24,651	28,195	29,785	29,969	30,233	30,500	30,653	30,724	30,796	30,867	30,936	31,005	31,072	31,139	31,204	31,269
Non-Residential Distributed Generation Program	13,717	13,568	12,980	14,036	15,092	16,148	17,205	18,261	19,317	20,373	21,430	22,486	23,542	24,598	25,655	26,711
Residential Bundle Program	48,326	72,360	94,434	98,787	106,160	116,454	127,304	128,477	130,973	131,389	132,045	133,192	134,312	135,405	136,474	137,529
Residential Home Energy Check-Up Program	4,363	4,704	4,817	4,844	4,872	4,900	4,918	4,928	6,236	5,466	4,958	4,968	4,977	4,987	4,996	5,005
Residential Duct Sealing Program	2,698	4,541	6,255	6,442	6,633	6,827	7,015	7,084	7,156	7,227	7,297	7,366	7,433	7,498	7,562	7,625
Residential Heat Pump Tune Up Program	15,500	21,519	27,042	29,575	35,092	43,493	52,530	53,021	53,523	54,025	54,517	54,998	55,468	55,926	56,375	56,817
Residential Heat Pump Upgrade Program	25,764	41,595	56,320	57,925	59,563	61,234	62,843	63,443	64,057	64,670	65,272	65,860	66,434	66,994	67,542	68,083
Non-Residential Window Film Program	2,756	7,168	12,793	18,920	20,781	21,196	21,453	21,660	21,896	22,212	22,277	22,477	22,673	22,866	23,057	23,246
Non-Residential Lighting Systems & Controls Program	9,948	16,044	22,230	29,420	29,980	30,551	30,843	31,464	34,550	31,640	31,901	32,158	32,410	32,658	32,904	33,147
Non-Residential Heating and Cooling Efficiency Program	4,879	10,489	17,185	23,984	27,618	28,051	28,405	28,676	28,951	29,225	29,496	29,762	30,023	30,280	30,582	30,786
Income and Age Qualifying Home Improvement Program	1,014	2,126	3,239	4,351	5,463	6,576	6,711	6,776	6,843	6,910	6,975	7,039	7,102	7,534	7,222	7,281
Residential Appliance Recycling Program	1,066	2,065	3,065	4,129	5,254	6,379	6,833	6,683	6,979	7,052	7,123	7,193	7,260	7,327	7,392	7,456
Total	288,012	342,307	385,037	403,532	409,672	411,584	407,514	408,562	416,153	418,619	421,947	425,603	425,188	426,855	427,729	429,132

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3O – Approved Programs Coincidental Peak Savings for Plan B: Intensity-Based Dual Rate
(kW) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Air Conditioner Cycling Program	113,861	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,107	121,108
Residential Low Income Program	1,654	1,654	1,654	1,654	1,654	1,654	1,654	1,654	1,547	1,166	759	475	154	0	0	0
Residential Lighting Program	26,020	26,020	22,307	16,480	10,288	3,119	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,149	10,149	10,149	10,149	9,187	5,347	1,340	87	36	0	0	0	0	0	0	0
Commercial HVAC Upgrade	670	670	670	670	670	670	670	670	670	584	341	88	0	0	0	0
Non-Residential Energy Audit Program	8,930	11,858	12,528	12,627	12,129	9,489	7,223	7,271	7,318	7,365	7,293	7,458	7,503	7,547	7,591	7,634
Non-Residential Duct Testing and Sealing Program	20,653	23,780	25,145	25,301	25,523	25,748	25,878	25,938	25,998	26,058	26,117	26,175	26,232	26,288	26,343	26,397
Non-Residential Distributed Generation Program	13,717	12,671	12,540	13,596	14,652	15,708	16,765	17,821	18,877	19,933	20,990	22,046	23,102	24,158	25,215	26,271
Residential Bundle Program	13,183	21,465	25,559	26,948	29,046	31,657	32,973	33,256	33,543	33,827	34,105	34,376	34,641	34,899	35,154	35,404
Residential Home Energy Check-Up Program	3,634	3,960	4,112	4,135	4,159	4,183	4,198	4,207	4,216	4,224	4,233	4,241	4,249	4,257	4,265	4,272
Residential Duct Sealing Program	574	1,196	1,486	1,530	1,575	1,621	1,650	1,666	1,683	1,700	1,716	1,732	1,747	1,762	1,777	1,792
Residential Heat Pump Tune Up Program	3,442	5,435	6,595	7,537	9,180	11,326	12,349	12,466	12,583	12,700	12,813	12,925	13,033	13,139	13,244	13,346
Residential Heat Pump Upgrade Program	5,533	10,874	13,366	13,746	14,133	14,528	14,775	14,918	15,061	15,203	15,343	15,479	15,611	15,741	15,868	15,994
Non-Residential Window Film Program	1,910	5,346	9,948	15,057	17,438	17,786	18,033	18,207	18,382	18,556	18,727	18,896	19,061	19,225	19,386	19,545
Non-Residential Lighting Systems & Controls Program	7,474	13,546	19,722	26,523	29,860	30,429	30,821	31,086	31,353	31,618	31,879	32,137	32,389	32,638	32,883	33,127
Non-Residential Heating and Cooling Efficiency Program	3,339	8,118	13,049	18,053	20,332	20,651	20,901	21,101	21,303	21,504	21,703	21,898	22,090	22,279	22,466	22,650
Income and Age Qualifying Home Improvement Program	509	1,059	1,772	2,485	3,198	3,910	4,231	4,273	4,315	4,357	4,397	4,437	4,476	4,514	4,551	4,588
Residential Appliance Recycling Program	851	1,701	2,775	3,850	4,924	5,998	6,486	6,331	6,624	6,693	6,761	6,827	6,891	6,954	7,016	7,077
Total	222,919	259,143	278,924	294,499	300,008	293,274	288,081	288,801	291,074	292,768	294,178	295,919	297,646	299,608	301,710	303,800

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3P – Approved Programs Energy Savings for Plan B: Intensity-Based Dual Rate (MWh) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Air Conditioner Cycling Program	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Low Income Program	9,951	9,951	9,951	9,951	9,951	9,951	9,951	9,951	9,343	7,023	4,305	2,445	797	0	0	0
Residential Lighting Program	276,557	276,557	239,911	177,573	112,328	36,461	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	82,912	82,702	82,702	82,702	75,552	45,159	11,804	707	322	0	0	0	0	0	0	0
Commercial HVAC Upgrade	3,645	3,641	3,641	3,641	3,645	3,641	3,641	3,641	3,645	3,214	1,939	537	0	0	0	0
Non-Residential Energy Audit Program	61,267	82,703	87,880	88,592	85,438	68,021	51,559	51,895	52,234	52,571	51,970	53,230	53,552	53,868	54,180	54,489
Non-Residential Duct Testing and Sealing Program	54,656	62,974	67,032	67,425	68,018	68,618	68,986	69,145	69,306	69,466	69,624	69,778	69,930	70,079	70,226	70,372
Non-Residential Distributed Generation Program	1	1	5	0	1	3	4	2	5	9	19	19	28	40	11	22
Residential Bundle Program	77,609	135,081	169,613	178,809	193,027	211,154	222,451	224,433	226,441	228,432	230,382	232,287	234,147	235,963	237,746	239,503
Residential Home Energy Check-Up Program	16,286	17,749	18,503	18,607	18,713	18,822	18,893	18,932	18,972	19,011	19,049	19,086	19,123	19,159	19,194	19,228
Residential Duct Sealing Program	3,571	7,949	10,486	10,798	11,116	11,441	11,670	11,787	11,905	12,023	12,138	12,250	12,360	12,467	12,572	12,676
Residential Heat Pump Tune Up Program	22,797	36,828	46,270	52,369	63,428	78,332	87,364	88,186	89,018	89,843	90,652	91,442	92,213	92,966	93,706	94,434
Residential Heat Pump Upgrade Program	34,954	72,555	94,354	97,035	99,770	102,560	104,524	105,529	106,546	107,555	108,543	109,509	110,451	111,371	112,275	113,165
Non-Residential Window Film Program	8,222	23,349	43,787	66,553	77,784	79,338	80,461	81,236	82,017	82,794	83,559	84,311	85,051	85,779	86,498	87,210
Non-Residential Lighting Systems & Controls Program	25,773	47,417	69,438	93,554	106,452	108,480	109,926	110,870	111,823	112,769	113,702	114,619	115,521	116,409	117,286	118,154
Non-Residential Heating and Cooling Efficiency Program	5,379	13,073	21,012	29,068	32,736	33,250	33,651	33,973	34,299	34,623	34,943	35,257	35,566	35,870	36,171	36,468
Income and Age Qualifying Home Improvement Program	2,084	4,325	7,346	10,367	13,389	16,410	17,924	18,100	18,278	18,454	18,627	18,796	18,961	19,122	19,280	19,436
Residential Appliance Recycling Program	4,726	9,451	15,557	21,663	27,769	33,875	36,847	35,859	37,635	38,027	38,411	38,786	39,152	39,510	39,861	40,207
Total	612,782	751,226	817,874	829,900	806,090	714,361	647,203	639,813	645,348	647,383	647,480	650,067	652,705	656,640	661,260	665,862

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3Q – Approved Programs Penetrations for Plan B: Intensity-Based Dual Rate
(System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Air Conditioner Cycling Program	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,557	119,558	119,558
Residential Low Income Program	12,090	12,090	12,090	12,090	12,090	12,090	12,090	12,090	10,659	6,539	4,003	2,000	0	0	0	0
Residential Lighting Program	7,798,234	7,798,234	5,890,547	4,259,629	2,243,150	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	2,456	2,456	2,456	2,456	2,057	749	21	21	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	127	127	127	127	127	127	127	127	127	99	40	0	0	0	0	0
Non-Residential Energy Audit Program	5,168	5,937	5,990	6,042	5,670	4,074	3,798	3,823	3,848	3,873	3,897	3,921	3,944	3,967	3,990	4,013
Non-Residential Duct Testing and Sealing Program	4,240	4,857	4,869	4,912	4,955	4,999	5,010	5,022	5,034	5,045	5,057	5,068	5,079	5,089	5,100	5,111
Non-Residential Distributed Generation Program	13	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Residential Bundle Program	195,852	285,941	302,963	339,180	394,746	460,251	464,281	468,407	472,533	476,586	480,545	484,412	488,184	491,871	495,511	499,090
Residential Home Energy Check-Up Program	36,352	39,573	39,794	40,020	40,250	40,485	40,568	40,652	40,737	40,820	40,901	40,980	41,058	41,133	41,208	41,281
Residential Duct Sealing Program	9,010	15,945	16,422	16,908	17,404	17,910	18,088	18,271	18,454	18,633	18,808	18,979	19,146	19,309	19,471	19,629
Residential Heat Pump Tune Up Program	116,552	172,413	187,082	220,899	274,017	337,025	340,175	343,400	346,625	349,793	352,887	355,910	358,858	361,740	364,585	367,383
Residential Heat Pump Upgrade Program	33,938	58,010	59,665	61,353	63,075	64,831	65,450	66,084	66,718	67,340	67,948	68,542	69,122	69,688	70,247	70,797
Non-Residential Window Film Program	869,884	2,094,703	3,557,599	5,108,280	5,210,289	5,314,338	5,365,319	5,417,180	5,469,085	5,520,346	5,570,777	5,620,387	5,669,151	5,717,153	5,764,715	5,811,768
Non-Residential Lighting Systems & Controls Program	2,660	4,293	5,950	7,876	8,026	8,179	8,249	8,320	8,391	8,462	8,531	8,599	8,666	8,732	8,797	8,862
Non-Residential Heating and Cooling Efficiency Program	902	1,736	2,586	3,446	3,500	3,555	3,589	3,623	3,658	3,692	3,726	3,759	3,792	3,824	3,856	3,887
Income and Age Qualifying Home Improvement Program	3,698	7,798	11,898	15,998	20,098	24,198	24,434	24,676	24,918	25,155	25,387	25,613	25,834	26,050	26,264	26,473
Residential Appliance Recycling Program	7,500	15,000	22,500	30,000	37,500	45,000	45,475	45,961	46,448	46,926	47,392	47,848	48,293	48,727	49,156	49,578
Total	9,022,381	10,352,740	9,939,144	9,909,606	8,061,779	5,997,132	6,051,967	6,108,825	6,164,276	6,216,299	6,268,932	6,321,186	6,372,522	6,424,994	6,476,971	6,528,365

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3R – Description of Proposed DSM Programs

Small Business Improvement Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2016 – 2038
NC Duration:	2017 – 2038

Program Description:
This Program would provide small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses would be required to meet certain connected load requirements.

Residential Programmable Thermostat Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2016 - 2038
NC Duration:	2017 - 2038

Program Description: This Program will provide an incentive to eligible customers who purchase specific types of Program-approved WiFi-connected programmable thermostats at retail outlets or through online retailers.

Appendix 3S – Proposed Programs Non-Coincidental Peak Savings for Plan B: Intensity-Based Dual Rate (kW) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Programmable Thermostat Program	0	624	1,161	1,600	2,064	2,554	2,761	2,793	2,825	2,857	2,889	2,919	2,949	2,978	3,007	3,035
Small Business Improvement Program	0	2,060	5,083	9,038	13,877	19,528	22,090	22,308	22,527	22,745	22,960	23,172	23,380	23,584	23,786	23,986
Total	0	2,685	6,244	10,638	15,941	22,083	24,851	25,101	25,353	25,603	25,849	26,091	26,329	26,563	26,793	27,022

Appendix 3T – Proposed Programs Coincidental Peak Savings for Plan B: Intensity-Based Dual Rate (kW) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Programmable Thermostat Program	0	502	1,100	1,527	1,979	2,457	2,678	2,709	2,740	2,771	2,802	2,831	2,860	2,889	2,916	2,944
Small Business Improvement Program	0	1,510	4,558	8,386	12,996	18,390	20,893	21,099	21,307	21,513	21,717	21,917	22,113	22,307	22,498	22,687
Total	0	2,012	5,659	9,913	14,975	20,847	23,571	23,808	24,047	24,285	24,518	24,748	24,974	25,195	25,414	25,631

Appendix 3U – Proposed Programs Energy Savings for Plan B: Intensity-Based Dual Rate
(MWh) (System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Programmable Thermostat Program	0	1,191	2,570	3,563	4,615	5,725	6,227	6,299	6,372	6,445	6,515	6,584	6,652	6,717	6,782	6,846
Small Business Improvement Program	0	5,090	15,734	29,117	45,246	64,134	73,384	74,108	74,838	75,563	76,278	76,981	77,672	78,352	79,023	79,688
Total	0	6,281	18,304	32,680	49,861	69,859	79,612	80,408	81,211	82,008	82,793	83,565	84,323	85,069	85,805	86,534

Appendix 3V – Proposed Programs Penetrations for Plan B: Intensity-Based Dual Rate

(System-Level)

Programs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Programmable Thermostat Program	0	2,000	2,954	3,973	5,046	6,180	6,251	6,324	6,397	6,468	6,538	6,607	6,673	6,738	6,803	6,866
Small Business Improvement Program	0	519	1,196	2,028	3,018	4,165	4,206	4,248	4,289	4,330	4,371	4,411	4,450	4,488	4,527	4,564
Total	0	2,519	4,150	6,001	8,064	10,345	10,457	10,572	10,686	10,799	10,909	11,017	11,123	11,227	11,329	11,430

Appendix 3W– Generation Interconnection Projects under Construction

Currently, there are no Generation Interconnection projects under construction.

Appendix 3X – List of Transmission Lines under Construction

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #222 Uprate from Northwest to Southwest	230	706	Jul-15	VA
Convert Line 64 to 230kV and Install 230kV Capacitor Bank at Winfall	230	775 (#2131) 840(#2126)	Sep-15	NC
Line #262 Rebuild (Yadkin - Chesapeake EC) and Line #2110 Reconductor (Suffolk - Thrasher)	230 230	1,047 1195	Oct-15	VA
Line #17 Uprate Shockoe - Northeast and Terminate Line #17 at Northeast	115	257	Nov-15	VA
Line #201 Rebuild	230	1,047	Nov-15	VA
Uprate Liine 2022 - Possum Point to Dumfries Substation	230	797	Dec-15	VA
Burton Switching Station and 115 kV Line to Oakwood	115	233	Dec-15	VA
Rebuild Line #551 (Mt Storm - Doubs)	500	4,334	Dec-15	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Jun-16	VA
New 230kV Line Dooms to Lexington	230	1,047	Jun-16	VA
Line #33 Rebuild and Halifax 230kV Ring Bus	115	353	Aug-16	VA

Appendix 3Y – Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2

VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

November 5, 2015

10 CFR Part 54

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Serial No.: 15-293
NL&OS/DEA: R0
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
INTENT TO PURSUE SECOND LICENSE RENEWAL

This letter provides notification of Virginia Electric and Power Company's (Dominion) intention to submit an application for the second renewed Operating Licenses for Surry Power Station, Units 1 and 2.

The first renewed Operating Licenses for Surry Power Station, Units 1 and 2 were issued on March 20, 2003 and will expire at midnight on May 25, 2032 and January 29, 2033, respectively. Dominion intends to submit an application for the second renewed Operating Licenses for Surry Power Station, Units 1 and 2 in accordance with 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," by the end of the first quarter of 2019.

This notification is being provided consistent with RIS 2009-06, "Importance of Giving NRC Advance Notice of Intent to Pursue License Renewal," dated June 15, 2009. As discussed in RIS 2009-006, Dominion will keep the NRC informed of any changes to the anticipated schedule for filing the second license renewal application for Surry Power Station to facilitate NRC efforts to plan for processing of license renewal applications.

If you have any questions regarding this information, please contact Mr. Tom Huber at (804) 273-2229.

Sincerely,

Mark Sartain
Vice President - Nuclear Engineering

Commitments made in this letter: None

Appendix 3Y cont. – Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2

Serial No. 15-293
Docket Nos. 50-280/281
Page 2 of 2

cc: U.S. Nuclear Regulatory Commission, Region II
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NRC Senior Resident Inspector
Surry Power Station

Appendix 4A – ICF Commodity Price Forecasts for Dominion Virginia Power

Fall 2015 Forecast

NOTICE PROVISIONS FOR AUTHORIZED THIRD PARTY USERS.

This report and information and statements herein are based in whole or in part on information obtained from various sources. ICF makes no assurances as to the accuracy of any such information or any conclusions based thereon. ICF is not responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

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ICF CPP Commodity Price Forecast (Nominal $)

	Fuel Price					Power and REC Prices				Emission Prices			
Year	Henry Hub Natural Gas ($/MMBtu)	DOM Zone Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/MMBtu)	No. 2 Oil ($/MMBtu)	1% No.6 Oil ($/MMBtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	RTO Capacity Prices ($/kW-yr)	CSAPR SO_2 ($/Ton)	CSAPR Ozone NO_x ($/Ton)	CSAPR Annual NO_x ($/Ton)	CO_2 ($/Ton)
2016	2.45	2.50	1.66	10.44	5.46	42.37	30.95	16.00	33.24	51.14	102.27	102.27	-
2017	2.89	2.98	1.81	11.66	6.66	43.45	32.01	16.56	34.64	27.16	73.13	73.13	-
2018	3.70	3.87	2.08	12.81	8.30	47.02	38.43	16.99	53.38	2.14	42.80	42.80	-
2019	4.54	4.71	2.26	13.79	9.32	51.27	43.43	18.69	62.93	2.19	43.85	43.85	-
2020	5.16	5.30	2.36	14.68	9.95	55.39	46.86	20.29	66.10	2.24	44.84	44.84	-
2021	5.40	5.52	2.42	15.23	10.33	58.09	49.31	22.00	69.50	2.29	45.79	45.79	-
2022	5.64	5.73	2.48	15.82	10.74	60.78	51.71	21.66	73.06	2.34	46.75	46.75	10.17
2023	5.89	5.92	2.54	16.40	11.15	63.13	54.00	21.33	76.76	2.38	47.70	47.70	10.85
2024	6.05	6.00	2.60	17.00	11.56	63.37	54.21	21.00	79.17	2.43	48.67	48.67	11.58
2025	6.22	6.11	2.66	17.65	12.01	63.98	54.73	20.67	79.97	2.48	49.66	49.66	12.36
2026	6.39	6.24	2.72	18.35	12.50	64.92	55.51	22.05	80.24	2.53	50.66	50.66	13.18
2027	6.57	6.51	2.79	19.08	13.02	67.08	57.35	23.53	81.43	2.58	51.69	51.69	14.06
2028	6.76	6.75	2.86	19.85	13.55	69.06	59.00	25.12	82.67	2.64	52.77	52.77	15.01
2029	6.95	7.04	2.92	20.68	14.13	71.41	60.97	26.81	83.93	2.69	53.87	53.87	16.03
2030	7.14	7.28	2.99	21.51	14.71	73.26	62.51	28.61	85.18	2.75	54.97	54.97	17.10
2031	7.55	7.75	3.06	22.31	15.27	77.19	65.91	26.25	88.63	2.80	56.10	56.10	18.25

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices for all commodities except emissions and capacity prices. 2019 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2018/2019, forecast thereafter. Emission prices are forecasted for all years. Refer to Sections 4.4.1 and 4.4.2 for additional details.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Natural Gas

	DOM Zone Natural Gas Price (Nominal $/MMBtu)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	2.50	2.50	2.50	2.50	2.50
2017	2.98	2.99	2.96	2.98	2.98
2018	3.87	4.05	3.74	3.88	3.87
2019	4.71	5.00	4.40	4.71	4.58
2020	5.30	5.64	4.86	5.30	5.03
2021	5.52	5.94	5.00	5.57	5.16
2022	5.73	6.24	5.14	5.84	5.27
2023	5.92	6.53	5.25	6.09	5.35
2024	6.00	6.69	5.30	6.20	5.45
2025	6.11	6.88	5.38	6.34	5.59
2026	6.24	7.11	5.49	6.51	5.75
2027	6.51	7.46	5.72	6.81	6.05
2028	6.75	7.81	5.94	7.10	6.32
2029	7.04	8.19	6.19	7.42	6.64
2030	7.28	8.53	6.40	7.70	6.91
2031	7.75	9.02	6.72	8.20	7.26

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Natural Gas

	Henry Hub Natural Gas Price (Nominal $/MMBtu)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	2.45	2.45	2.45	2.45	2.45
2017	2.89	2.90	2.87	2.89	2.89
2018	3.70	3.87	3.56	3.70	3.70
2019	4.54	4.82	4.22	4.54	4.40
2020	5.16	5.50	4.71	5.15	4.89
2021	5.40	5.82	4.88	5.45	5.03
2022	5.64	6.15	5.05	5.75	5.17
2023	5.89	6.49	5.22	6.05	5.32
2024	6.05	6.74	5.35	6.25	5.51
2025	6.22	7.00	5.49	6.45	5.70
2026	6.39	7.26	5.64	6.66	5.90
2027	6.57	7.53	5.79	6.88	6.11
2028	6.76	7.81	5.94	7.10	6.32
2029	6.95	8.10	6.10	7.33	6.54
2030	7.14	8.39	6.26	7.56	6.77
2031	7.55	8.82	6.51	8.00	7.06

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Coal: FOB

	CAPP 12,500 1% S Coal (Nominal $/MMBtu)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	1.66	1.66	1.66	1.66	1.66
2017	1.81	1.81	1.80	1.81	1.81
2018	2.08	2.14	2.01	2.08	2.10
2019	2.26	2.38	2.09	2.25	2.28
2020	2.36	2.52	2.12	2.35	2.39
2021	2.42	2.61	2.10	2.41	2.45
2022	2.48	2.69	2.08	2.48	2.51
2023	2.54	2.77	2.07	2.54	2.57
2024	2.60	2.84	2.12	2.60	2.63
2025	2.66	2.91	2.17	2.65	2.69
2026	2.72	2.98	2.22	2.71	2.75
2027	2.79	3.05	2.28	2.78	2.81
2028	2.86	3.12	2.33	2.84	2.88
2029	2.92	3.19	2.39	2.91	2.94
2030	2.99	3.27	2.45	2.97	3.01
2031	3.06	3.35	2.51	3.03	3.08

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Oil

	No. 2 Oil (Nominal $/MMBtu)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	10.44	10.44	10.44	10.44	10.44
2017	11.66	11.76	11.59	11.66	11.66
2018	12.81	13.68	12.25	12.81	12.81
2019	13.79	15.41	12.71	13.79	13.79
2020	14.68	16.27	13.24	14.68	14.68
2021	15.23	17.15	13.77	15.23	15.23
2022	15.82	18.04	14.32	15.82	15.82
2023	16.40	18.96	14.87	16.40	16.40
2024	17.00	19.90	15.44	17.00	17.00
2025	17.65	20.88	15.95	17.65	17.65
2026	18.35	21.82	16.50	18.35	18.35
2027	19.08	22.80	17.08	19.08	19.08
2028	19.85	23.83	17.68	19.85	19.85
2029	20.68	24.92	18.31	20.68	20.68
2030	21.51	26.03	18.95	21.51	21.51
2031	22.31	27.18	19.49	22.31	22.31

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Oil

	1% No. 6 Oil (Nominal $/MMBtu)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	5.46	5.46	5.46	5.46	5.46
2017	6.66	6.73	6.62	6.66	6.66
2018	8.30	8.92	7.90	8.30	8.30
2019	9.32	10.49	8.55	9.32	9.32
2020	9.95	11.09	8.92	9.95	9.95
2021	10.33	11.70	9.29	10.33	10.33
2022	10.74	12.33	9.66	10.74	10.74
2023	11.15	12.98	10.05	11.15	11.15
2024	11.56	13.64	10.45	11.56	11.56
2025	12.01	14.33	10.80	12.01	12.01
2026	12.50	14.99	11.18	12.50	12.50
2027	13.02	15.68	11.58	13.02	13.02
2028	13.55	16.40	12.00	13.55	13.55
2029	14.13	17.17	12.44	14.13	14.13
2030	14.71	17.95	12.88	14.71	14.71
2031	15.27	18.76	13.25	15.27	15.27

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; On-Peak Power Price

	DOM Zone Power On-Peak (Nominal $/MWh)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	42.37	42.37	42.37	42.37	42.37
2017	43.45	43.53	43.31	43.57	43.40
2018	47.02	48.33	46.04	47.98	46.72
2019	51.27	53.53	48.91	52.79	49.77
2020	55.39	58.14	52.10	57.13	52.93
2021	58.09	61.56	54.21	60.30	54.31
2022	60.78	65.02	56.29	63.48	55.60
2023	63.13	68.16	58.00	66.31	56.51
2024	63.37	69.02	57.93	66.87	56.89
2025	63.98	70.25	58.24	67.81	57.65
2026	64.92	71.83	58.87	69.11	58.73
2027	67.08	74.59	60.76	71.66	61.01
2028	69.06	77.20	62.44	74.04	63.10
2029	71.41	80.16	64.48	76.80	65.54
2030	73.26	82.66	66.00	79.06	67.49
2031	77.19	86.61	68.89	84.73	70.51

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; Off-Peak Power Price

	DOM Zone Power Off-Peak (Nominal $/MWh)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	30.95	30.95	30.95	30.95	30.95
2017	32.01	32.08	31.89	32.09	31.96
2018	38.43	39.53	37.54	39.13	38.14
2019	43.43	45.34	41.44	44.60	42.12
2020	46.86	49.18	44.22	48.27	44.75
2021	49.31	52.39	45.95	51.15	45.79
2022	51.71	55.61	47.60	54.01	46.71
2023	54.00	58.76	49.07	56.75	47.43
2024	54.21	59.49	49.00	57.32	47.77
2025	54.73	60.54	49.25	58.22	48.42
2026	55.51	61.86	49.75	59.39	49.31
2027	57.35	64.23	51.32	61.66	51.23
2028	59.00	66.42	52.69	63.76	52.95
2029	60.97	68.93	54.37	66.19	54.99
2030	62.51	71.02	55.61	68.20	56.60
2031	65.91	74.49	58.07	73.51	59.24

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices (Nominal $/MWh)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	16.00	16.00	16.00	16.00	16.00
2017	16.56	16.56	16.56	16.56	16.56
2018	16.99	16.99	16.99	16.99	16.99
2019	18.69	18.26	19.26	18.05	19.34
2020	20.29	19.37	21.53	18.91	21.72
2021	22.00	20.51	24.04	19.79	24.36
2022	21.66	19.46	24.08	19.26	25.03
2023	21.33	18.45	24.11	18.74	25.70
2024	21.00	17.49	24.13	18.23	26.40
2025	20.67	16.59	24.16	17.73	27.11
2026	22.05	17.42	25.77	17.59	28.14
2027	23.53	18.31	27.50	17.44	29.22
2028	25.12	19.25	29.36	17.30	30.35
2029	26.81	20.23	31.34	17.17	31.53
2030	28.61	21.26	33.44	17.03	32.74
2031	26.25	18.79	32.79	15.10	31.26

Note: The 2016 - 2018 prices are a blend of futures/forwards and forecast prices. 2019 and beyond are forecast prices.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; PJM RTO Capacity

	RTO Capacity Prices (Nominal $/KW-yr)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	33.24	33.24	33.24	33.24	33.24
2017	34.64	34.64	34.64	34.64	34.64
2018	53.38	53.38	53.38	53.38	53.38
2019	62.93	62.93	62.93	62.93	62.93
2020	66.10	65.24	66.77	68.29	73.98
2021	69.50	67.60	71.00	74.17	83.69
2022	73.06	70.38	75.17	79.38	88.36
2023	76.76	73.25	79.55	84.91	93.25
2024	79.17	75.04	82.80	89.35	96.43
2025	79.97	75.37	84.54	91.16	97.67
2026	80.24	75.17	85.79	91.65	98.39
2027	81.43	75.87	88.00	93.07	100.05
2028	82.67	76.60	90.31	94.56	101.78
2029	83.93	77.32	92.67	96.06	103.53
2030	85.18	78.02	95.07	97.56	105.29
2031	88.63	81.48	98.68	101.25	108.89

Note: PJM RPM auction clearing prices through delivery year 2018/19, forecast thereafter.

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; SO_2 Emission Allowances

	CSAPR SO_2 Prices (Nominal $/Ton)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	51.14	51.14	51.14	51.14	51.14
2017	27.16	27.16	27.16	27.16	27.16
2018	2.14	2.14	2.14	2.14	2.14
2019	2.19	2.19	2.19	2.19	2.19
2020	2.24	2.24	2.24	2.24	2.24
2021	2.29	2.29	2.29	2.29	2.29
2022	2.34	2.34	2.34	2.34	2.34
2023	2.38	2.38	2.38	2.38	2.38
2024	2.43	2.43	2.43	2.43	2.43
2025	2.48	2.48	2.48	2.48	2.48
2026	2.53	2.53	2.53	2.53	2.53
2027	2.58	2.58	2.58	2.58	2.58
2028	2.64	2.64	2.64	2.64	2.64
2029	2.69	2.69	2.69	2.69	2.69
2030	2.75	2.75	2.75	2.75	2.75
2031	2.80	2.80	2.80	2.80	2.80

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; NO_x Emission Allowances

	CSAPR Ozone NO_x Prices (Nominal $/Ton)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	102.27	102.27	102.27	102.27	102.27
2017	73.13	73.13	73.13	73.13	73.13
2018	42.80	42.80	42.80	42.80	42.80
2019	43.85	43.85	43.85	43.85	43.85
2020	44.84	44.84	44.84	44.84	44.84
2021	45.79	45.79	45.79	45.79	45.79
2022	46.75	46.75	46.75	46.75	46.75
2023	47.70	47.70	47.70	47.70	47.70
2024	48.67	48.67	48.67	48.67	48.67
2025	49.66	49.66	49.66	49.66	49.66
2026	50.66	50.66	50.66	50.66	50.66
2027	51.69	51.69	51.69	51.69	51.69
2028	52.77	52.77	52.77	52.77	52.77
2029	53.87	53.87	53.87	53.87	53.87
2030	54.97	54.97	54.97	54.97	54.97
2031	56.10	56.10	56.10	56.10	56.10

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; NO_x Emission Allowances

	CSAPR Annual NO_x Prices (Nominal $/Ton)				
Year	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	102.27	102.27	102.27	102.27	102.27
2017	73.13	73.13	73.13	73.13	73.13
2018	42.80	42.80	42.80	42.80	42.80
2019	43.85	43.85	43.85	43.85	43.85
2020	44.84	44.84	44.84	44.84	44.84
2021	45.79	45.79	45.79	45.79	45.79
2022	46.75	46.75	46.75	46.75	46.75
2023	47.70	47.70	47.70	47.70	47.70
2024	48.67	48.67	48.67	48.67	48.67
2025	49.66	49.66	49.66	49.66	49.66
2026	50.66	50.66	50.66	50.66	50.66
2027	51.69	51.69	51.69	51.69	51.69
2028	52.77	52.77	52.77	52.77	52.77
2029	53.87	53.87	53.87	53.87	53.87
2030	54.97	54.97	54.97	54.97	54.97
2031	56.10	56.10	56.10	56.10	56.10

ICF CPP Commodity Case, No CO_2 Cost Case and Scenario Price Forecast; CO_2

Year	CO_2 (Nominal $/Ton)				
	CPP Commodity Case	High Fuel Cost Scenario	Low Fuel Cost Scenario	ICF Reference Scenario	No CO_2 Cost Case
2016	-	-	-	-	-
2017	-	-	-	-	-
2018	-	-	-	-	-
2019	-	-	-	-	-
2020	-	-	-	-	-
2021	-	-	-	-	-
2022	10.17	13.05	8.29	5.71	-
2023	10.85	13.93	8.85	6.30	-
2024	11.58	14.86	9.44	6.94	-
2025	12.36	15.86	10.07	7.66	-
2026	13.18	16.92	10.75	8.45	-
2027	14.06	18.05	11.47	9.32	-
2028	15.01	19.27	12.24	10.28	-
2029	16.03	20.57	13.07	11.34	-
2030	17.10	21.95	13.95	12.51	-
2031	18.25	23.43	14.88	14.71	-

Note: The CO_2 price forecasts shown above apply to states that adopt a Mass-Based compliance program. States that adopt an Intensity-Based compliance program would use ERCs which are forecasted to be abundantly available and are priced at $0/ton. Refer to Sections 4.4.1 and 4.4.2 for additional details.

Projected State CPP Program

	Projected State CPP Program	
	Mass-Based	Intensity-Based
1	AL	FL
2	AR	GA
3	AZ	IA
4	CA	ID
5	CO	IL
6	CT	MN
7	DE	ND
8	IN	NM
9	KS	NV
10	KY	OK
11	LA	SC
12	MA	TN
13	MD	TX
14	ME	VA
15	MI	
16	MO	
17	MS	
18	MT	
19	NC	
20	NE	
21	NH	
22	NJ	
23	NY	
24	OH	
25	OR	
26	PA	
27	RI	
28	SD	
29	UT	
30	WA	
31	WI	
32	WV	
33	WY	

Appendix 4B – Delivered Fuel Data for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 18**

FUEL DATA

	(ACTUAL)				(PROJECTED)														
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.68	0.68	0.67	0.63	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67	0.69	0.70	0.71	0.72	0.73	0.74	0.74
b. Coal	3.15	3.04	2.87	1.66	1.81	2.08	2.26	2.36	2.42	2.48	2.54	2.60	2.66	2.72	2.79	2.86	2.92	2.99	3.06
c. Heavy Fuel Oil	15.27	16.33	7.78	5.46	6.66	8.30	9.32	9.95	10.33	10.74	11.15	11.56	12.01	12.50	13.02	13.55	14.13	14.71	15.27
d. Light Fuel Oil(2)	19.89	21.60	14.54	10.44	11.66	12.81	13.79	14.68	15.23	15.82	16.40	17.00	17.65	18.35	19.08	19.85	20.68	21.51	22.31
e. Natural Gas	3.07	5.96	4.11	2.50	2.98	3.87	4.71	5.30	5.52	5.73	5.92	6.00	6.11	6.24	6.51	6.75	7.04	7.28	7.75
f. Renewable(3)	1.85	3.07	3.16	3.22	3.25	3.27	3.33	3.36	3.39	3.45	3.52	3.59	3.67	3.73	3.81	3.88	3.96	4.06	4.15
II. Primary Fuel Expenses (cents/kWh)(4)																			
a. Nuclear	0.71	0.70	0.69	0.68	0.71	0.70	0.70	0.70	0.70	0.70	0.69	0.71	0.72	0.73	0.75	0.75	0.76	0.77	0.78
b. Coal	3.22	3.26	3.13	2.18	2.36	2.65	2.84	2.97	3.06	3.21	3.32	3.40	3.47	3.57	3.64	3.72	3.83	3.91	4.00
c. Heavy Fuel Oil	13.91	15.16	12.25	5.35	15.28	7.96	11.28	16.54	95.64	11.62	15.98	20.66	17.52	17.72	20.57	20.24	10.41	24.12	23.08
d. Light Fuel Oil(2)	4.57	15.46	11.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
e. Natural Gas	2.76	4.33	3.03	1.72	2.17	2.46	2.85	3.34	3.45	3.58	3.67	3.76	3.82	4.10	4.06	4.15	4.28	4.36	4.64
f. Renewable(3)	2.95	4.26	4.93	4.61	4.73	4.53	4.59	4.70	4.76	4.84	4.94	5.04	5.16	5.25	5.41	5.51	5.63	5.75	5.88
g. NUG(5)	3.02	4.30	3.21	1.57	1.47	1.20	1.30	1.64	1.49	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
i. Economy Energy Purchases(6)	3.78	6.38	4.56	2.15	2.20	2.81	2.67	3.60	3.09	3.12	3.75	3.35	3.32	4.46	3.66	4.00	4.82	3.73	3.92
j. Capacity Purchases ($/kW-Year)	20.24	31.77	49.57	33.24	34.64	53.38	62.93	66.10	69.50	73.06	76.76	79.17	79.97	80.24	81.43	82.67	83.93	85.18	88.63

(1) Delivered fuel price for CAPP CSX (12,500, 1% FOB), No. 2 Oil, No. 6 Oil, DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil and Natural Gas respectively.

(2) Light fuel oil is used for reliability only at dual-fuel facilities.

(3) Reflects biomass units only.

(4) Primary Fuel Expenses for Nuclear, Coal, Heavy Fuel Oil, Natural Gas and Renewable are based on North Anna 1, Chesterfield 6, Yorktown 3, Possum Point 6, Pittsylvania, respectively.

(5) Average of NUGs Fuel Expenses.

(6) Average cost of Market Energy Purchases.

Appendix 5A - Tabular Results of Busbar

	Capacity Factor (%)										
$/kW-Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
CC 3x1	$ 181	$ 242	$ 303	$ 364	$ 426	$ 487	$ 548	$ 609	$ 670	$ 731	$ 792
CC 2x1	$ 205	$ 268	$ 331	$ 394	$ 457	$ 520	$ 583	$ 646	$ 709	$ 772	$ 835
CC 1x1	$ 260	$ 328	$ 396	$ 464	$ 532	$ 600	$ 668	$ 736	$ 804	$ 872	$ 940
CT	$ 62	$ 154	$ 246	$ 339	$ 431	$ 523	$ 616	$ 708	$ 800	$ 893	$ 985
Nuclear	$ 1,122	$ 1,132	$ 1,143	$ 1,153	$ 1,164	$ 1,174	$ 1,185	$ 1,195	$ 1,206	$ 1,216	$ 1,227
Solar PV w/ Battery	$ 1,241	$ 1,226	$ 1,211	$ 1,196							
SCPC w/ CCS	$ 704	$ 849	$ 995	$ 1,140	$ 1,285	$ 1,430	$ 1,576	$ 1,721	$ 1,866	$ 2,011	$ 2,157
IGCC w/CCS	$ 1,471	$ 1,605	$ 1,738	$ 1,872	$ 2,006	$ 2,140	$ 2,274	$ 2,408	$ 2,542	$ 2,675	$ 2,809
VOWTAP (1)					$ 2,854						
Offshore Wind (1)					$ 1,373						
Onshore Wind (2)					$ 417						
Fuel Cell	$ 971	$ 1,031	$ 1,090	$ 1,150	$ 1,209	$ 1,269	$ 1,328	$ 1,387	$ 1,447	$ 1,506	$ 1,566
Solar PV (3)				$ 171							
Biomass	$ 913	$ 971	$ 1,030	$ 1,089	$ 1,147	$ 1,206	$ 1,265	$ 1,323	$ 1,382	$ 1,441	$ 1,499

(1) VOWTAP and Offshore Wind both have a capacity factor of 42%.

(2) Onshore Wind has a capacity factor of 37%.

(3) Solar PV has a capacity factor of 25%.

Appendix 5B - Busbar Assumptions

Nominal $	Heat Rate	Variable Cost [1][2]	Fixed Cost	Book Life	2016 Real $ [3]
	MMBtu/MWh	$/MWh	$/kW-Year	Years	$/kW
CC 3x1	6.55	69.70	181.29	36	820
CC 2x1	6.59	71.92	205.26	36	981
CC 1x1	6.63	77.69	259.57	36	1,314
CT	9.07	61.51	105.40	36	444
Nuclear	10.50	12.01	1,121.74	60	8,705
Solar PV w/ Battery	-	(17.21)	1,241.03	25	14,074
SCPC w/ CCS	11.06	165.83	704.09	55	5,193
IGCC w/CCS	10.88	152.79	1,470.80	40	10,851
VOWTAP	-	(18.83)	2,922.88	20	19,122
Offshore Wind	-	(18.83)	1,441.40	20	8,276
Onshore Wind	-	(43.90)	557.19	25	3,702
Fuel Cell	8.75	67.82	971.45	20	5,990
Solar PV	-	(17.21)	209.82	25	-
Biomass	13.00	66.95	912.73	40	5,909

(1) Variable cost for Biomass, Solar PV, Solar PV w/Battery, Onshore Wind, Offshore Wind and VOWTAP includes value for RECs.

(2) Variable cost for Biomass and Onshore Wind includes value for PTCs.

(3) Values in this column represent overnight installed costs.

Appendix 5C – Planned Generation under Development for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 15c**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(2)	MW Summer	MW Nameplate
Under Development(1)						
VOWTAP	VA	Intermittent	Wind	2018	2	11(3)
VA Solar[4]	VA	Intermittent	Solar	2020	235	400
North Anna 3	Mineral, VA	Baseload	Nuclear	2029	1,452	1,452

(1) Includes the additional resources under development in the Studied Plans.

(2) Estimated Commercial Operation Date.

(3) Accounts for line losses.

(4) VA Solar includes Scott, Whitehouse and Woodland Solar (56 MW total).

Appendix 5D – Standard DSM Test Descriptions

Participant Test

The Participant test is the measure of the quantifiable benefits and costs to program participants due to enrollment in a program. This test indicates whether the program or measure is economically attractive to the customer enrolled in the program. Benefits include the participant's retail bill savings over time plus any incentives offered by the utility, while costs include only the participant's costs. A result of 1.0 or higher indicates that a program is beneficial for the participant.

Utility Cost Test

The Utility Cost test compares the cost to the utility to implement a program to the cost that is expected to be avoided as a result of the program implementation. The Utility Cost test measures the net costs and benefits of a DSM program as a resource option, based on the costs and benefits incurred by the utility including incentive costs and excluding any net costs incurred by the participant. The Utility Cost test ignores participant costs, meaning that a measure could pass the Utility Cost test, but may not be cost-effective from a more comprehensive perspective. A result of 1.0 or higher indicates that a program is beneficial for the utility.

Total Resource Cost Test

The TRC test compares the total costs and benefits to the utility and participants, relative to the costs to the utility and participants. It can also be viewed as a combination of the Participant and Utility Cost tests, measuring the impacts to the utility and all program participants as if they were treated as one group. Additionally, this test considers customer incentives as a pass-through benefit to customers and, therefore, does not include customer incentives. If a program passes the TRC test, then it is a viable program absent any equity issues associated with non-participants. A result of 1.0 or higher indicates that a program is beneficial for both participants and the utility.

Ratepayer Impact Measure Test

The RIM test considers equity issues related to programs. This test determines the impact the DSM program will have on non-participants and measures what happens to customer bills or rates due to changes in utility revenues and operating costs attributed to the program. A score on the RIM test of greater than 1.0 indicates the program is beneficial for both participants and non-participants, because it should have the effect of lowering bills or rates even for customers not participating in the program. Conversely, a score on the RIM test of less than 1.0 indicates the program is not as beneficial because the costs to implement the program exceed the benefits shared by all customers, including non-participants.

Appendix 5E – DSM Programs Energy Savings for Plan B: Intensity-Based Dual Rate

(MWh)

(System-Level)

Company Name: Virginia Electric & Power Company

Schedule 12

Energy Efficiency/Energy Efficiency- Demand Response/Peak Shaving/Demand Side Management (MWh)

					ACTUAL - MWh			(PROJECTED - MWh)															
Program Type [1]	**Program Name**	**Date [2]**	**Life/ Duration [3]**	**Size kW [4]**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Peak Shaving	Air Conditioner Cycling Program	2010	2031	121,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total				**121,108**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Energy Efficiency - Demand Response	Non-Residential Distributed Generation Program	2010	2031	26,271				1	1	5	0	1	3	4	2	5	9	19	19	28	40	11	22
	Standby Generation (Pricing Tariffs) [5]	1987	2031	2,459	227	276	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
Sub-total				**28,730**	**227**	**276**	**342**	**342**	**343**	**346**	**342**	**343**	**345**	**346**	**344**	**347**	**351**	**361**	**361**	**369**	**382**	**353**	**364**
Energy Efficiency	Residential Low Income Program	2010	2028	0	4,518	5,333	6,121	9,951	9,951	9,951	9,951	9,951	9,951	9,951	9,951	9,343	7,023	4,305	2,445	797	0	0	0
	Residential Lighting Program	2010	2021	0	228,892	228,892	228,892	276,557	276,557	239,911	177,573	112,328	36,461	0	0	0	0	0	0	0	0	0	0
	Commercial Lighting Program	2010	2022	0	72,620	72,947	73,417	82,912	82,702	82,702	82,702	75,552	45,159	11,804	707	322	0	0	0	0	0	0	0
	Commercial HVAC Upgrade	2010	2027	0	5,936	5,936	5,936	3,645	3,641	3,641	3,641	3,645	3,641	3,641	3,641	3,645	3,214	1,939	537	0	0	0	0
	Non-Residential Energy Audit Program	2010	2031	7,634	746	8,661	40,705	61,267	82,703	87,880	88,592	85,438	68,021	51,559	51,895	52,234	52,571	51,970	53,230	53,552	53,868	54,180	54,489
	Non-Residential Duct Testing and Sealing Program	2012	2031	26,397	492	11,663	36,861	54,656	62,974	67,032	67,425	68,018	68,618	68,986	69,145	69,306	69,466	69,624	69,778	69,930	70,079	70,226	70,372
	Residential Bundle Program	2010 [6]	2031	35,404	4,152	18,001	38,474	77,609	135,081	169,613	178,809	193,027	211,154	222,451	224,433	226,441	228,432	230,382	232,287	234,147	235,963	237,746	239,503
	Residential Home Energy Check-Up Program	2012	2031	4,272	354	7,079	20,049	16,286	17,749	18,503	18,607	18,713	18,822	18,893	18,932	18,972	19,011	19,049	19,086	19,123	19,159	19,194	19,228
	Residential Duct Sealing Program	2012	2031	1,792	34	79	439	3,571	7,949	10,486	10,798	11,116	11,441	11,670	11,787	11,905	12,023	12,138	12,250	12,360	12,467	12,572	12,676
	Residential Heat Pump Tune Up Program	2012	2031	13,346	2,629	7,278	13,000	22,797	36,828	46,270	52,369	63,428	78,332	87,364	88,186	89,018	89,843	90,652	91,442	92,213	92,966	93,706	94,434
	Residential Heat Pump Upgrade Program	2012	2031	15,994	1,134	3,565	4,985	34,954	72,555	94,354	97,035	99,770	102,560	104,524	105,529	106,546	107,555	108,543	109,509	110,451	111,371	112,275	113,165
	Non-Residential Window Film Program	2014	2031	19,545	0	77	2,769	8,222	23,349	43,787	66,553	77,784	79,338	80,461	81,236	82,017	82,794	83,559	84,311	85,051	85,779	86,498	87,210
	Non-Residential Lighting Systems & Controls Program	2014	2031	33,127	0	427	22,171	25,773	47,417	69,438	93,554	106,452	108,480	109,926	110,870	111,823	112,769	113,702	114,619	115,521	116,409	117,286	118,154
	Non-Residential Heating and Cooling Efficiency Program	2014	2031	22,650	0	135	8,376	5,379	13,073	21,012	29,068	32,736	33,250	33,651	33,973	34,299	34,623	34,943	35,257	35,566	35,870	36,171	36,468
	Income and Age Qualifying Home Improvement Program	2015	2031	4,588	0	0	104	2,084	4,325	7,346	10,367	13,389	16,410	17,924	18,100	18,278	18,454	18,627	18,796	18,961	19,122	19,280	19,436
	Residential Appliance Recycling Program	2015	2031	7,077	0	0	659	4,726	9,451	15,557	21,663	27,769	33,875	36,847	35,859	37,635	38,027	38,411	38,786	39,152	39,510	39,861	40,207
	Residential Programmable Thermostat Program		2031	2,944	0	0	0	0	1,191	2,570	3,563	4,615	5,725	6,227	6,299	6,372	6,445	6,515	6,584	6,652	6,717	6,782	6,846
	Small Business Improvement Program		2031	22,687	0	0	0	0	5,090	15,734	29,117	45,246	64,134	73,384	74,108	74,838	75,563	76,278	76,981	77,672	78,352	79,023	79,688
	Voltage Conservation Program [7]				21,862	33,236	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total				**182,053**	**339,218**	**385,308**	**464,485**	**612,781**	**757,506**	**836,174**	**862,580**	**855,950**	**784,216**	**726,811**	**720,219**	**726,554**	**729,382**	**730,255**	**733,613**	**737,001**	**741,669**	**747,054**	**752,374**
Total Demand Side Management				**331,890**	**339,445**	**385,584**	**464,827**	**613,123**	**757,848**	**836,520**	**862,922**	**856,293**	**784,561**	**727,157**	**720,563**	**726,901**	**729,732**	**730,615**	**733,974**	**737,371**	**742,051**	**747,407**	**752,738**

(1) The Program types have been categorized by the Virginia definitions of peak shaving, energy efficiency, and demand response.

(2) Implementation date.

(3) State expected life of facility or duration of purchase contract. The Company used Program Life (Years).

(4) The MWs reflected as of 2031.

(5) Reductions available during on-peak hours.

(6) Residential Bundle is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.

(7) Voltage Conservation Energy Savings not calculated for 2015.

Appendix 5F – Planned Generation Interconnection Projects

Line Terminal	PJM Queue	Line Voltage (kV)	Line Capacity	Interconnection Cost (Million $)	Target Date	Location
Carson - Rogers Rd	Z1-086	500	4,300	3	Dec-17	VA
Heritage - Rogers Rd	Z1-086	500	4,300	3	Dec-17	VA
* North Anna – Ladysmith	Q-65	500	4,300	48	Apr-24	VA

*Subject to change based on receipt of applicable regulatory approval(s).

Appendix 5G – List of Planned Transmission Lines

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #222 Uprate from Northwest to Southwest	230	706	Jul-15	VA
Convert Line 64 to 230kV and Install 230kV Capacitor Bank at Winfall	230	775 (#2131)	Sep-15	NC
Line #262 Rebuild (Yadkin - Chesapeake EC) Line #2110 Reconductor (Suffolk - Thrasher)	230 230	1,047 1,195	Oct-15	VA
Line #17 Uprate Shockoe - Northeast and Terminate Line #17 at Northeast	115	231	Nov-15	VA
Line #201 Rebuild	230	1,200	Nov-15	VA
Uprate Line 2022 - Possum Point to Dumfries Substation	230	797	Dec-15	VA
Burton Switching Station and 115 kV Line to Oakwood	115	233	Dec-15	VA
Rebuild Line #551 (Mt Storm - Doubs)	500	4,334	Dec-15	VA
New 115kV DP to Replace Pointon 34.5kV DP - SEC	115	230	Mar-16	VA
Line #2090 Uprate	230	1,195	May-16	VA
Line #2032 Uprate (Elmont - Four Rivers)	230	1,195	May-16	VA
Loudoun – Pleasant View Line #558 Rebuild	500	4,000	May-16	VA
Line #2104 Reconductor and Upgrade (Fredericksburg - Cranes Corner)	230	1,047	May-16	VA
Rebuild Line #2027 (Bremo - Midlothian)	230	1,047	May-16	VA
230kV Line Extension to new Pacific Substation	230	1,047	May-16	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Jun-16	VA
Line #22 Rebuild Carolina - Eatons Ferry	115	262	Jun-16	NC
Line #54 Reconductor Carolina - Woodland	115	306	Jun-16	NC
New 230kV Line Dooms to Lexington	230	1,047	Jun-16	VA
Line #87 Rebuild from Chesapeake to Churchland	115	239	Jun-16	VA
Line #33 Rebuild and Halifax 230kV Ring Bus	115	353	Aug-16	VA
Line #1 Rebuild - Crewe to Fort Pickett DP	115	261	Dec-16	VA
Line #18 and Line #145 Rebuild	115	524	Dec-16	VA
Line #4 Rebuild Between Bremo and Structure #8474	115	262	Dec-16	VA
Surry - Skiffes Creek 500 kV Line	500	4,325	Apr-17	VA
Skiffes Creek - Whealton 230 kV Line	230	1,047	Apr-17	VA
*Line #2161 Wheeler to Gainesville (part of Warrenton project)	230	1,047	May-17	VA
*Line #2174 Vint Hill to Wheeler (part of Warrenton project)	230	1,047	May-17	VA
Line #69 Uprate Reams DP to Purdy	115	300	Jun-17	VA
Line #82 Rebuild - Everetts to Voice of America	115	261	Dec-17	NC
Line #65 - Remove from the Whitestone Bridge	115	147	Dec-17	VA
*Network Line 2086 from Warrenton	230	1,047	May-18	VA
* 230kV Line Extension to new Haymarket Substation	230	1,047	May-18	VA
Line #47 Rebuild (Kings Dominion to Fredericksburg)	115	353	May-18	VA
Line #47 Rebuild (Four Rivers to Kings Dominion)	115	353	May-18	VA
Line #159 Reconductor and Uprate	115	353	May-18	VA
*Idylwood to Scotts Run – New 230kV Line and Scotts Run Substation	230	1,047	May-18	VA
* Reconfigure Line #4 Bremo to Cartersville	115	89	May-18	VA
230kV Line Extension to new Yardley Ridge DP	230	1,047	May-18	VA
230kV Line Extension to new Poland Road Sub	230	1,047	May-18	VA
New 230kV Line Remington to O'Neals (FirstEnergy)	230	1,047	Jun-18	VA
Line #553 (Cunningham to Elmont) Rebuild and Uprate	500	4,000	Jun-18	VA
Brambleton to Mosby 2nd 500kV Line	500	4,000	Jun-18	VA
Line #48 and #107 Partial Rebuild	115	317(#48) 353(#107)	Dec-18	VA
Line #34 and Line #61 (partial) Rebuild	115	353 (#34)	Dec-18	VA
Line #2104 Reconductor and Upgrade (Cranes Corner - Stafford)	230	1,047	May-19	VA
Line #27 and #67 Rebuild from Greenwich to Burton	115	262	Dec-19	VA
* 230kV Line Extension to new Harry Byrd Sub	230	1,047	May-20	VA
Rebuild Mt Storm -Valley 500 kV Line	500	4,000	Jun-21	VA
Rebuild Dooms to Valley 500 kV Line	500	4,000	Dec-21	VA

Note: Asterisk reflects planned transmission addition subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s).

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Appendix 5H – Cost Estimates for Nuclear License Extensions

	Capital Cost
North Anna Units 1 & 2	[redacted]
Surry Units 1 & 2	

Appendix 6A – Renewable Resources for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 11**

RENEWABLE RESOURCE GENERATION (GWh)

Resource Type[1]	Unit Name	C.O.D.[2]	Build/Purchase/ Convert[3]	Life/ Duration[4]	Size MW[5]	2013 (ACTUAL)	2014 (ACTUAL)	2015 (ACTUAL)	2016	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hydro																								
	Cushaw Hydro	Jan-30	Build	60	2	14	12	9	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	Gaston Hydro	Feb-63	Build	60	220	301	309	316	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253
	North Anna Hydro	Dec-87	Build	60	1	1	3	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	Sep-55	Build	60	95	300	296	288	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253
Sub-total					318	616	620	617	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521
Solar																								
	Solar Partnership Program	2013-2016	Build	20	7	-	0.3	2	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Existing NC Solar NUGs	2014	Purchase	20	600	-	-	161	879	1,312	1,306	1,299	1,296	1,286	1,280	1,273	1,270	1,261	1,254	1,248	1,245	1,236	1,230	1,223
	VA Solar by 2020	2020	Build	35	400			-	86	226	330	529	868	861	857	853	851	844	840	836	834	827	823	819
	Solar 2020	2020	Build	35	200	-	-	-	-	-	-	-	441	438	436	433	432	429	427	425	424	421	418	416
	Solar 2021	2021	Build	35	200	-	-	-	-	-	-	-	-	440	438	436	435	431	429	427	426	423	421	418
	Solar 2022	2022	Build	35	200	-	-	-	-	-	-	-	-	-	440	438	437	433	431	429	428	425	423	421
	Solar 2023	2023	Build	35	200	-	-	-	-	-	-	-	-	-	-	440	439	436	433	431	430	427	425	423
	Solar 2024	2024	Build	35	200	-	-	-	-	-	-	-	-	-	-	-	441	438	436	433	432	429	427	425
	Solar 2025	2025	Build	35	100	-	-	-	-	-	-	-	-	-	-	-	-	220	219	218	217	216	215	213
Sub-total					2,507	-	0.3	164	1,058	1,773	1,973	2,366	3,481	3,895	4,315	4,734	5,163	5,344	5,317	5,291	5,277	5,238	5,212	5,186
Biomass	**Unit Name**																							
	Pittsylvania	Jun-94	Purchase	60	83	369	324	267	61	130	213	323	460	594	481	493	484	490	565	601	659	660	612	630
	Virginia City Hybrid Energy Center [6]	Apr-12	Build	60	61	11	58	100	153	199	256	286	329	345	281	300	281	281	301	281	284	288	279	308
	Altavista	Feb-92	Convert	30	51	145	227	269	351	392	392	392	393	400	392	392	393	392	392	392	393	392	392	417
	Southampton	Mar-92	Convert	30	51	56	253	290	393	400	400	400	401	400	392	392	393	392	392	392	393	392	392	417
	Hopewell	Jul-92	Convert	30	51	85	266	263	393	392	400	400	401	400	392	392	393	392	392	392	393	392	392	410
	Covanta Fairfax	-	Purchase	-	-	553	591	218	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total					297	1,219	1,719	1,407	1,352	1,512	1,661	1,802	1,985	2,139	1,937	1,968	1,944	1,947	2,041	2,058	2,122	2,123	2,067	2,181
Wind																								
	VOWTAP	Jan-21	Build	20	12	-	-	-	-	-	-	-	-	40	40	40	41	40	40	40	41	40	40	40
Sub-total					12	-	-	-	-	-	-	-	-	40	40	40	41	40	40	40	41	40	40	40
Total Renewables					3,133	1,835	2,339	2,187	2,932	3,807	4,156	4,689	5,987	6,596	6,814	7,263	7,669	7,853	7,920	7,910	7,962	7,923	7,840	7,928

(1) Per definition of § 56-576 of the Code of Virginia.

(2) Commercial Operation Date.

(3) Company built, purchased or converted.

(4) Expected life of facility or duration of purchase contract.

(5) Net Summer Capacity for Biomass and Hydro, Nameplate for Solar and Wind.

(6) Dual fired coal & biomass reaching 61 MW in 2021.

Appendix 6B – Potential Supply-Side Resources for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Solar 2020	N/A	Intermittent	Solar	2020	117	200
Solar 2021	N/A	Intermittent	Solar	2021	117	200
Generic CC 2022	N/A	Intermediate/Baseload	Natural Gas-Combined Cycle	2022	1,591	1,591
Solar 2022	N/A	Intermittent	Solar	2022	117	200
Generic CT 2023	N/A	Peak	Natural Gas-Turbine	2023	458	458
Solar 2023	N/A	Intermittent	Solar	2023	117	200
Solar 2024	N/A	Intermittent	Solar	2024	117	200
Solar 2025	N/A	Intermittent	Solar	2025	59	100
Generic CC 2030	N/A	Intermediate/Baseload	Natural Gas-Combined Cycle	2030	1,591	1,591

(1) Estimated Commercial Operation Date.

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Appendix 6C – Summer Capacity Position for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 16

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)					(PROJECTED)													
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Existing Capacity																			
Conventional	17,265	17,885	18,928	19,240	18,759	18,752	18,667	18,661	18,658	17,469	17,469	17,469	17,469	17,469	17,469	17,469	17,469	17,469	17,469
Renewable	400	554	553	588	594	600	606	612	615	615	615	615	615	615	615	615	615	615	615
Total Existing Capacity	17,665	18,439	19,481	19,827	19,352	19,352	19,273	19,273	19,273	18,084	18,084	18,084	18,084	18,084	18,084	18,084	18,084	18,084	18,084
Generation Under Construction																			
Conventional	-	-	-	-	-	-	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Renewable	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Planned Construction Capacity	-	-	-	2	2	2	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587	1,587
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	15	34	57	89	107	124	139	151	163	171	180	185	188	192
Total Planned Development Capacity	-	-	-	-	-	15	34	57	89	107	124	139	151	163	171	180	185	188	192
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	-	-	-	1,591	2,049	2,049	2,049	2,049	2,049	2,049	2,049	3,640	3,640
Renewable	-	-	-	-	-	-	-	-	30	74	129	195	267	335	384	428	467	498	526
Total Potential New Capacity	-	-	-	-	-	-	-	-	30	1,666	2,178	2,244	2,316	2,384	2,433	2,477	2,516	4,139	4,167
Other (NUG)	1,787	1,749	1,775	1,277	714	569	400	426	458	259	283	301	314	327	332	344	346	350	348
Unforced Availability	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Generation Capacity	19,451	20,188	20,203	21,107	20,068	19,938	21,294	21,343	21,438	21,703	22,256	22,355	22,452	22,545	22,607	22,671	22,718	24,348	24,378
Existing DSM Reductions																			
Demand Response	5	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions[1]	5	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Approved DSM Reductions																			
Demand Response[4]	83	117	82	128	134	134	135	136	137	138	139	140	141	142	143	144	145	146	147
Conservation/Efficiency[2,4]	47	51	69	95	125	145	160	164	156	150	150	151	152	152	153	153	154	155	156
Total Approved DSM Reductions	130	168	151	223	259	279	294	300	293	288	289	291	293	294	296	298	300	302	304
Future DSM Reductions																			
Demand Response[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency[2]	-	-	-	-	2	6	10	15	21	24	24	24	24	25	25	25	25	25	26
Total Future DSM Reductions	-	-	-	-	2	6	10	15	21	24	24	24	24	25	25	25	25	25	26
Total Demand-Side Reductions[1]	135	171	153	223	261	285	304	315	314	312	313	315	317	319	321	323	325	327	329
Net Generation & Demand-side	19,586	20,359	20,355	21,330	20,329	20,223	21,599	21,658	21,752	22,015	22,569	22,670	22,769	22,864	22,928	22,994	23,043	24,675	24,707
Capacity Sale[3]	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
Capacity Purchase[3]								1	89	105	1	153	355	483	638	754	982	1	72
Capacity Adjustment[3]								-	-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation	[redacted]							21,480	21,664	21,946	22,396	22,647	22,948	23,170	23,389	23,570	23,845	24,495	24,597
Net Utility Capacity Position	[redacted]							1	89	105	1	153	355	483	638	754	982	1	72

(1) Existing DSM programs are included in the load forecast.

(2) Efficiency programs are not part of the Company's calculation of capacity.

(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.

(4) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

Appendix 6D – Construction Forecast for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company **Schedule 17**

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. New Traditional Generating Facilities[3]																
a. Construction Expenditure (Not AFUDC)[2]	923,523	654,654	735,682	1,009,572	525,203	447,012	220,733	113,631	82,647	143,655	436,093	938,778	507,523	407,481	369,628	646,007
b. AFUDC[1]	4,533	5,680	5,780	6,127	8,836	10,361	727	554	778	1,097	1,913	3,847	5,883	7,171	3,777	5,205
c. Annual Total	928,056	660,334	741,463	1,015,699	534,039	457,373	221,460	114,185	83,425	144,752	438,005	942,625	513,405	414,651	373,405	651,212
d. Cumulative Total	928,056	1,588,390	2,329,853	3,345,551	3,879,590	4,336,963	4,558,423	4,672,608	4,756,033	4,900,785	5,338,790	6,281,416	6,794,821	7,209,472	7,582,878	8,234,090
II. New Renewable Generating Facilities																
a. Construction Expenditure (Not AFUDC)	158,936	113,887	8,494	94,171	281,056	1,475	-	-	-	-	-	-	-	-	-	-
b. AFUDC[1]	1,955	238	56	200	518	-	-	-	-	-	-	-	-	-	-	-
c. Annual Total	160,891	114,125	8,550	94,371	281,575	1,475	-	-	-	-	-	-	-	-	-	-
d. Cumulative Total	160,891	275,016	283,565	377,936	659,511	660,986	660,986	660,986	660,986	660,986	660,986	660,986	660,986	660,986	660,986	660,986
III. Other Facilities																
a. Transmission	841,477	699,806	666,877	679,518	676,438	726,521	733,786	741,124	748,535	756,020	763,581	771,216	778,928	786,718	794,585	802,531
b. Distribution	715,307	765,151	828,277	830,813	848,716	863,589	872,224	880,947	889,756	898,654	907,640	784,717	750,884	760,143	769,494	778,939
c. Energy Conservation & DR[3]	2,000	2,045	2,095	2,144	2,189	2,234	2,256	2,278	2,301	2,324	2,347	2,371	2,395	2,419	2,443	2,467
d. Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. AFUDC	27,523	32,901	26,623	24,417	31,702	37,254	37,627	38,003	38,383	38,767	39,155	39,546	39,942	40,341	40,745	41,152
f. Annual Total	1,586,306	1,499,903	1,523,872	1,536,892	1,559,045	1,629,597	1,645,893	1,662,352	1,678,976	1,695,765	1,712,723	1,597,850	1,572,149	1,589,620	1,607,266	1,625,089
g. Cumulative Total	1,586,306	3,086,209	4,610,081	6,146,973	7,706,018	9,335,615	10,981,508	12,643,860	14,322,836	16,018,601	17,731,324	19,329,174	20,901,323	22,490,943	24,098,209	25,723,298
IV. Total Construction Expenditures																
a. Annual	2,675,253	2,274,362	2,273,885	2,646,962	2,374,658	2,088,445	1,867,353	1,776,537	1,762,400	1,840,517	2,150,728	2,540,476	2,085,554	2,004,271	1,980,672	2,276,301
b. Cumulative	2,675,253	4,949,614	7,223,499	9,870,461	12,245,119	14,333,564	16,200,917	17,977,454	19,739,855	21,580,372	23,731,100	26,271,576	28,357,130	30,361,401	32,342,073	34,618,374
V. % of Funds for Total Construction Provided from External Financing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Does not include Construction Work in Progress.

(2) The construction expenditure includes both modeled and budgeted expenditures.

Confidential Information Redacted

Appendix 6E – Capacity Position for Plan B: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA

Schedule 4

	(ACTUAL)							(PROJECTED)											
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity[1]	17,665	18,439	19,481	19,829	19,354	19,369	20,894	20,917	20,979	21,444	21,973	22,054	22,138	22,218	22,275	22,328	22,372	23,998	24,030
b. Positive Interchange Commitments[2]	1,747	1,747	1,757	1,277	714	569	400	426	458	259	283	301	314	327	332	344	346	350	348
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	5	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
e. Demand Response - Approved[5]	83	117	82	128	134	134	135	136	137	138	139	140	141	142	143	144	145	146	147
f. Demand Response - Future[5]	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Capacity Sale[3]	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
h. Capacity Purchase[3]	[redacted]							1	89	105	1	153	355	483	638	754	982	1	72
i. Capacity Adjustment[3]	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
j. Total Net Summer Capability[4]	[redacted]							21,478	21,662	21,944	22,394	22,645	22,946	23,168	23,387	23,568	23,843	24,493	24,595
2. Winter																			
a. Installed Net Dependable Capacity[1]	-	-	-	19,534	20,505	20,505	22,222	22,124	22,154	22,673	23,186	23,222	23,257	23,292	23,317	23,340	23,359	25,066	25,080
b. Positive Interchange Commitments[2]	-	-	-	1,381	1,399	497	514	314	328	114	124	132	138	144	146	151	152	153	153
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response[5]	15	15	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Demand Response-Existing[6]	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
f. Total Net Winter Capability[4]	-	-	-	20,914	21,904	21,002	22,736	22,437	22,482	22,786	23,310	23,353	23,395	23,436	23,463	23,491	23,511	25,219	25,233

(1) Net Seasonal Capability.

(2) Includes firm commitments from existing Non-Utility Generation and estimated solar NUGs.

(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.

(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MW.

(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

(6) Included in the winter capacity forecast.

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INSIGHT

The Future of Fuel: Opportunities in an Evolving Global Market

By Kevin Petak, Hua Fang, and Michael Sloan

Shareables

1. ICF forecasts that 2016 will be prime time for assets to change hands. Midstream companies, investors, and utilities in the United States will need to update their portfolios to capture cost efficiencies within the Marcellus/Utica juggernaut and unload less cost-efficient resources to stay afloat.
2. Although most forecasters believe that prices will begin to increase only after 2020, ICF predicts that gas prices will rebound much sooner.
3. ICF sees the future of gas prices as hinging on the growth in demand for LNG and Mexican exports.

Executive Summary

Natural gas prices are at some of the lowest levels we have seen in history, in large part due to the Marcellus/Utica shale gas revolution in the United States. What are the implications of these ultra-low natural gas prices, when can we anticipate gas prices to rebound, and how can utilities, developers, and investors create value in this environment? In a recent webinar, three of ICF's gas experts—Kevin Petak, Hua Fang, and Michael Sloan—explored the current state of gas markets to try to address these questions. In the coming year, midstream companies will need to shift their assets to take advantage of the growth in cost-effective supplies within the Marcellus/Utica markets and to unload less cost-effective resources. Similarly, financial firms will want to take a fresh look at the value of their investments, focusing specifically on the promising Southwest region of the Marcellus/Utica. Utilities also have an opportunity to improve their situation by taking positions in infrastructure assets. Perhaps most notably, ICF anticipates that North America is positioned to be the next big gas exporter. As a result, ICF predicts that gas prices will rebound within the next 3–5 years because of growth in global demand for LNG and Mexican exports.

Immediate Implications of Low Gas Prices

Natural gas prices have dropped to record inflation-adjusted lows. Between December 2015 and February 2016, natural gas prices teetered between $1.93/MMBtu and $2.28/MMBtu[1]. These rock-bottom gas prices are being driven by asymmetrical supply-demand: The United States has a robust natural gas supply surplus stacked against a weak level of demand. The repercussions of this strong supply-weak demand equation are being felt throughout the industry—with producers struggling to stay afloat and midstream companies trying to reassess their asset strategy.

One question needling many U.S.-based utilities, equity firms, and midstream companies is: "When will we start to see a rebound in natural gas prices?" Although most forecasters believe that prices will begin to increase only after 2020, ICF predicts that gas prices will actually rebound much sooner due to the growing demand for liquefied natural gas (LNG) and Mexican exports over the next 3–5 years.

"North American gas prices are so competitive relative to other global sources, so it makes sense for foreign buyers of gas to be looking at the North American market as part of their portfolio for natural gas," said Petak.

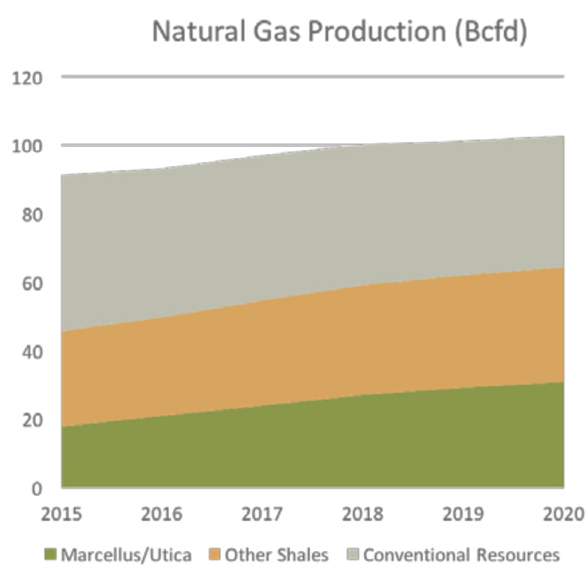
[1] https://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm history: https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm

But the growth in gas demand is not yet a slam dunk. The global energy market has many moving parts, and it is impossible to predict exactly how each element will unfold and influence demand for—and thus prices of—natural gas. Given the uncertain future of global gas demand, it is important to balance the future perspective with a close look inward to the evolving U.S. gas market to assess the immediate implications of low gas prices and to understand potential opportunities for growth.

Currently, Marcellus/Utica shale gas dominates the U.S. gas market. The Marcellus/Utica revolution has driven gas prices down everywhere, from the East Coast to Henry Hub to the West Coast. ICF estimates that the Marcellus/Utica natural gas supply will continue to grow from 19 bcfd in 2015 to 30 bcfd by 2020 (Figure 1), which means that Marcellus/Utica will continue to dictate gas prices—cannibalizing other supplies—particularly higher cost gas and shale plays.

Three pricing points exemplify the changes in the Marcellus/Utica market. Dominion South Point is considered a generic point to value production out of Southwest Pennsylvania, Ohio, and West Virginia. Texas Eastern's M2 (Tetco M2) originally reflects costs of gas from the Gulf Coast to Northeast before the shale revolution. Finally, Leidy, located in Northeast Pennsylvania, is considered a pricing proxy for Marcellus/Utica production in Northeast Pennsylvania counties.

Figure 1. Shale Gas Dominates Projected Natural Gas Production from 2015-2020



Source: ICF International

Because gas supply has shifted so significantly within the United States, utilities have had to redesign their gas pipeline infrastructure. Historically, most U.S. gas came from Texas and Louisiana and later from the Rockies, so utilities designed the nation's gas pipelines to move gas East and North. But given the Marcellus/Utica shale revolution, U.S. gas supplies are shifting to Pennsylvania, Ohio, and West Virginia, which means that instead of building long pipelines that traverse from West to East, companies are creating shorter pipelines to move gas from Pennsylvania to New York, Virginia, and Boston and from Ohio to the Midwest, South Atlantic, and Mid-Atlantic. For the first time ever, it is cheaper to transport gas from East to West than from West to East. These evolving changes driven by Marcellus/Utica gas markets have made it challenging for asset holders to assess the value of gas.

How will such low gas prices influence demand within the United States? ICF does not foresee a fundamental shift in end-use gas demand in North America in the short term. As a result, low gas prices driven by Marcellus/Utica will cause some producers to go bankrupt, which could, in turn, accelerate declines of older supplies and compel companies to reassess their assets. A potential outcome is that

bankruptcies could help prices rebound. If a major producer goes bankrupt, those reserves may be held hostage until the situation is resolved. During this time, the producer's declining activity would bring the market into a more balanced supply-demand ratio faster and create a spike in gas prices as demand recovers. And when prices do rebound, as ICF predicts will happen, some of the less cost-efficient supplies will spring back to life.

Opportunities and Risks in the Current Natural Gas Market

Given the low gas prices and risk of bankruptcies, key players in the U.S. gas market will need to assess the present opportunities and risks in the natural gas landscape in order to stay relevant.

Overall, ICF predicts that 2016 will be a robust time for assets changing hands, particularly when producers realign their portfolios and try to capture some of the cost efficiencies within the Marcellus/Utica juggernaut and unload less cost-efficient resources. Upstream and midstream companies, in particular, will face tremendous financial pressure to show off their balance sheets or begin restructuring to continue their operations—and thus will have to reassess their assets and take advantage of the growth in cost-effective supplies. But these companies will need help from financial firms to maneuver this dangerous landscape.

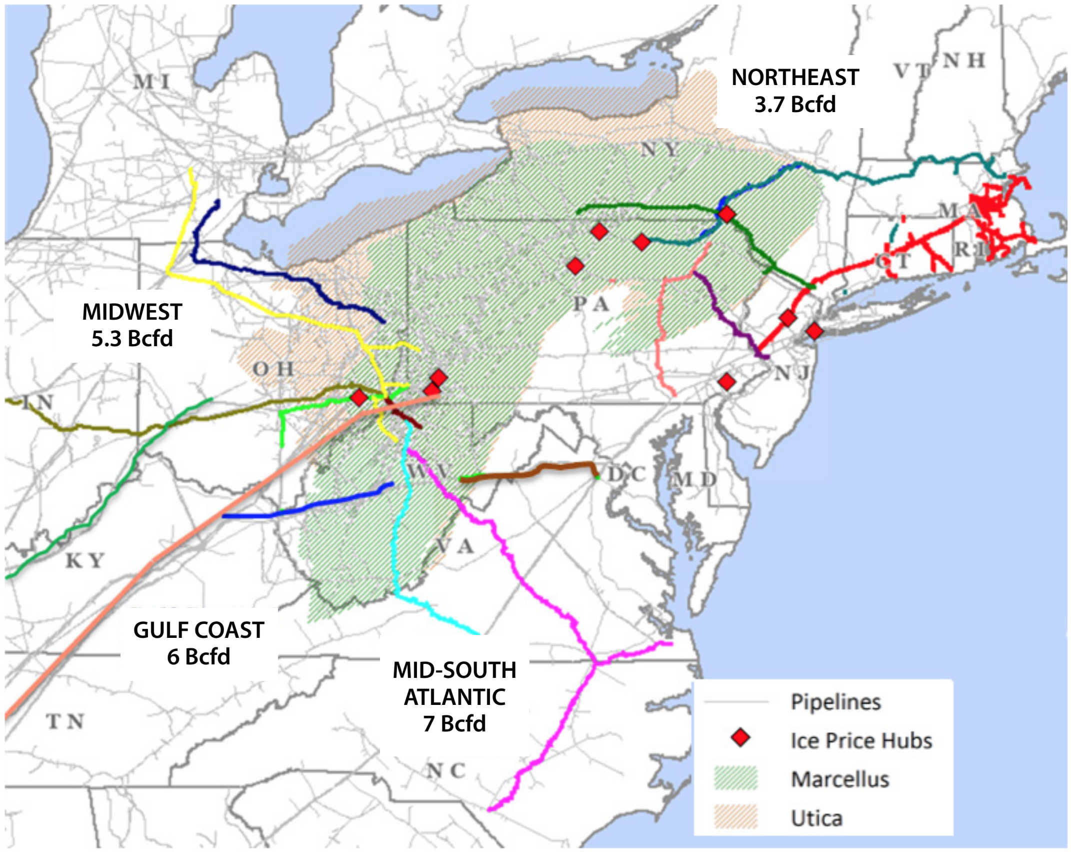
"I think the financial industry will be faced with a lot of opportunities to reevaluate the fair value of those upstream and midstream firms' assets holdings," said Fang.

The value of these assets will be based in part on their location and quality, but primarily on market factors, including market access, growth potential, and future infrastructure development. Investors can assess value in the following four main ways:

1. **Location.** Location represents the primary driver for reserve value and production potential under a low-price environment. Cost of production and exploration could be significantly different depending on geological characteristics of the underlying resources.
2. **Infrastructure.** Is there a pipeline infrastructure or proposed pipeline build that will take production to market?
3. **Market.** Access to fast-growing markets and future infrastructure development makes the asset more valuable.
4. **Leverage.** A producer's balance sheet determines how long the producer can sustain low prices.

With new pipeline proposals out of the Marcellus area, ICF predicts bigger price improvements in the Southwest than in the Northeast. The map (Figure 2) indicates where some of the new pipelines will be located.

Figure 2. Proposed Pipeline Infrastructure Along Marcellus/Utica Affects Resource Value



Source: ICF International

Much of the proposed new infrastructure would be constructed out of Dominion South Point territory: Southwest Pennsylvania, Ohio, and West Virginia. The new pipeline would funnel into the Midwest, West, the Gulf, and along the East Coast, bringing gas into the Carolinas and Georgia, where the power market is strong.

"Based on this trend, at least in the next few years, if we see the price of natural gas bounce back, the implication will be that Dominion South Point will be at an advantaged position compared to Leidy and producers in Northeast Pennsylvania because of the diversified path leading to different markets," Fang said.

Low oil prices discourage local distribution company (LDC) system expansion in the Northeast—a factor that is already causing producers to delay some pipeline projects. But this waning commitment to new pipeline builds is not all bad news. Such hesitations from producers may create opportunities for some LDCs and end users to step up to the plate and invest in pipeline growth.

"Fortunately, there is a strong set of justifications for LDCs and end-users to step in and support new pipeline expansion," Sloan said.

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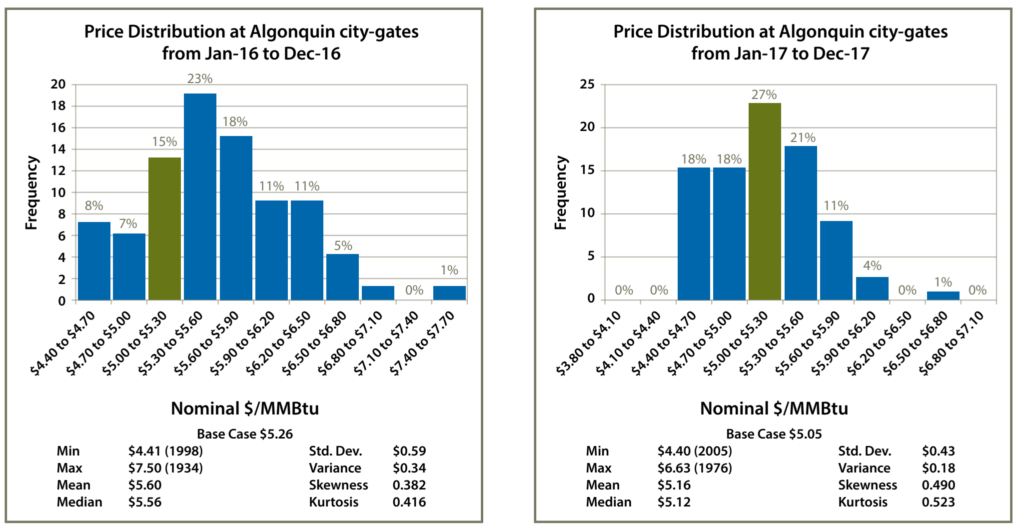
LDCs have three key reasons to want to contract new pipeline capacity, particularly out of the Appalachian basin.

1. LDCs will have access to lower cost supply basins.
2. The additional pipeline capacity will drive down Algonquin city-gate gas prices.
3. New pipelines will help reduce future gas price volatility.

The combination of access to lower cost supply and the ability to drive regional prices down provides significant benefit to utilities contracted to new pipeline supply. The following charts predict how the pipeline expansion will reduce future gas price volatility in New England in 2016 versus 2017 (Figure 3).

Figure 3. Weather Variability Effect Less Skewed at Algonquin City-gates in 2017 versus 2016



Source: ICF International

Once new pipeline projects begin to increase capacity in New England, the volatility will go down in those regions because of the enhanced pipeline capacity. In 2016, the price distribution is predicted to be much wider, spanning $4.40/MMBtu up to $7.70/MMBtu, while in 2017, this distribution narrows from $4.40 to $6.80 and is more highly concentrated in the lower range: $4.40/MMBtu to $5.90/MMBtu, indicating reduced volatility.

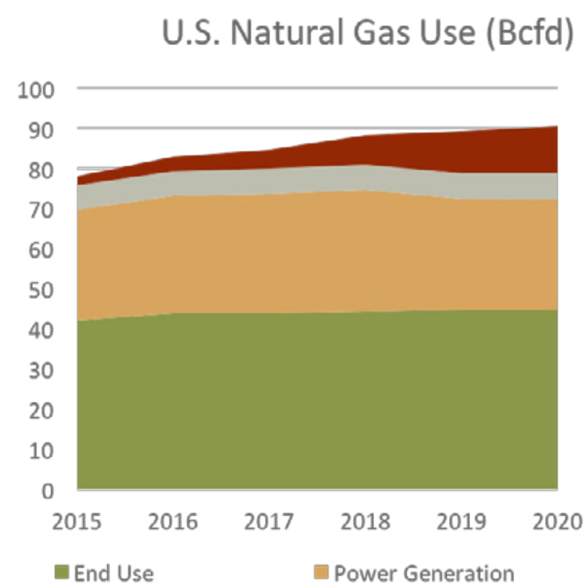
"When we look at other regions we see exactly the same thing—when we add pipeline capacity, we see lower prices and lower volatility providing significant benefits to LDCs, as they are provided the opportunity to shift their gas supply portfolio to take advantage of growth in Appalachian shale," said Sloan.

Gas Prices Rebound: Projections and Implications for the Future

Increasing demand is the key to increasing gas prices, and three factors have the potential to drive up demand. The first is that U.S. electricity consumers will demand more gas from the power sector as coal plants continue to retire and as new combined cycle plants are called upon to replace lost generation. This current trend seems likely to continue in the near and medium term. Second, growth in overall consumer electricity demand above replacing coal generation could also drive incremental gas demand growth. But neither factor is likely to increase electricity or gas demand significantly enough to boost gas prices.

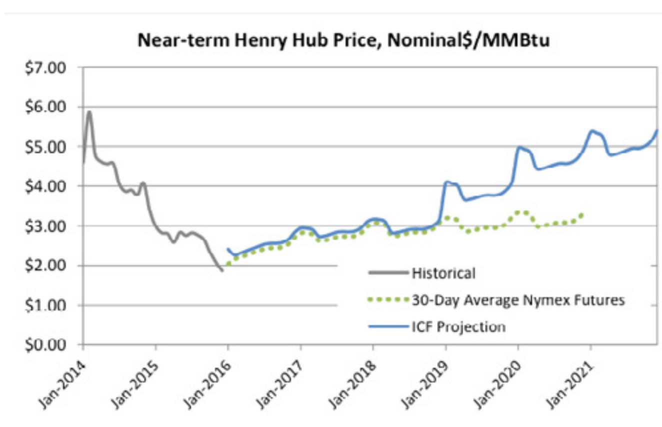
The more likely scenario leading to demand growth is that North American gas demand will increasingly come from LNG and Mexican exports, and this growing demand for LNG and Mexican exports will, in turn, pump up gas prices. Although many forecasters predict that LNG and Mexican exports will be the key to turning demand around for gas producers and midstream developers, they do not necessarily agree on when this transition will occur. Most believe that the shift in demand will begin only after 2020; ICF, on the other hand, predicts that this will happen faster and in turn, gas prices will rebound over the next 3–5 years. ICF forecasts that LNG and Mexican exports will rise to 10 bcfd by 2018 and approach 12 bcfd in 2020 (Figure 4), which will cause gas prices to surge from the low $2/MMBtu range into the $4 MMBtu ballpark in that time (Figure 5).

Figure 4. Exports Drive Projected Growth in Demand Through 2020



Source: ICF International

Figure 5. Price Rebound Projected in Gas Prices through 2021



Annual Average Henry Hub Price, Nominal$/MMBtu		
	ICF Projection	30-Day Avg NYMEX Futures
2014	4.34	4.34
2015	2.61	2.61
2016	2.50	2.36
2017	2.87	2.76
2018	2.98	2.90
2019	3.86	3.02
2020	4.67	3.15
2021	5.06	3.28

Source: ICF International

"The surprise in our projection…is we do see a price surge around 2018 and thereafter," Petak said. "It's not a done deal that this will happen, but our base case shows that the United States will switch from a net importer to a net exporter by 2018."

As this predicted shift occurs, the U.S. economy may reap significant rewards. ICF estimates that LNG exports could contribute $10–$31 billion to the economies of natural gas-producing states, such as Texas, Louisiana, and Pennsylvania[2]. The focus on natural gas exports could mean tens of thousands of new jobs in states that produce and manufacture natural gas as well as those that build LNG export terminals. But several main challenges and uncertainties exist for LNG and Mexican export demand.

- First, demand growth will likely be uneven, which means that supply will continue to outpace demand over the next few years. Because demand is tied to the development of terminals—which tends to be lumpy—it will take several years before demand catches up to supply.
- Next, and perhaps more importantly, global markets remain in flux. This uncertain economic growth, particularly in Asia—a potentially big destination for gas exports from the United States—creates uncertainty surrounding the level of demand for LNG and Mexican exports. As such, the United States faces the very real risk of overbuilding liquefaction capacity.
- Competition from other nations will be part of the equation as well. Competing forces from around the globe may hamper demand for North American gas: Gazprom, for instance, will try to retain market share by keeping gas prices competitive in Europe to shut out the United States.
- Last but not least, low oil prices may continue to keep gas prices down.

"The billion dollar question going forward," said Petak, "is whether this relationship between oil and gas prices will break down over time."

Conclusion

There are several takeaways for key players looking to find opportunities and minimize risk in an evolving gas market.

1. Midstream companies, investors, and LDCs and end-users need to focus on capturing the cost efficiencies in the Marcellus/Utica gas market, particularly in the Southwest Pennsylvania region.
2. Future demand growth in the United States will likely be uneven, but North America is positioned to be the next big gas exporter.
3. ICF predicts that gas prices will start to rebound by 2018.

[2] ICF International and EnSys Energy, "The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs," March 31, 2014 and "Supplement State-Level Economic and Employment Impacts," May 9, 2014. http://www.api.org/~/media/Files/Policy/LNG-Exports/LNG-primer/Liquefied-Natural-Gas-exports-lowres.pdf

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About ICF International

ICF International (NASDAQ:ICFI) provides professional services and technology solutions that deliver beneficial impact in areas critical to the world's future. ICF is fluent in the language of change, whether driven by markets, technology, or policy. Since 1969, we have combined a passion for our work with deep industry expertise to tackle our clients' most important challenges. We partner with clients around the globe—advising, executing, innovating—to help them define and achieve success. Our more than 5,000 employees serve government and commercial clients from more than 65 offices worldwide. ICF's website is www.icfi.com.

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Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases

May 17, 2016

The *Annual Energy Outlook 2016* (AEO2016) Early Release features two cases: the Reference case and a case excluding implementation of the Clean Power Plan (CPP)

Reference case: A business-as-usual trend estimate, given known technology and technological and demographic trends. The Reference case assumes CPP compliance through mass-based standards that establish caps on CO2 emissions from fossil-fired generators covered by the CPP. The mass-based standards are modeled using allowances with cooperation across states at the regional level, with all allowance revenues rebated to ratepayers.

No CPP case: A business-as-usual trend estimate, but assumes that CPP is not implemented.

Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development

- Projections are not statements of what will happen but of what might happen given the assumption and methodologies used for any particular case. The Reference case projection is a business-as-usual trend estimate reflecting current laws and regulations, known technology, and technological and demographic trends.

- While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior.

- Energy projections are subject to much uncertainty, as many of the events that shape energy markets, including future developments in technologies, resources, policies, and geopolitics, cannot be foreseen with certainty. Some key uncertainties in the AEO2016 projections are addressed through alternative cases, which will be published in the full AEO2016 release.

The AEO2016, to be issued in early summer 2016, will include a full range of Clean Power Plan (CPP) and other alternative cases, including:

- Alternative CPP cases: Rate-based implementation (applying limits on CO2 emissions per kilowatthour from covered sources), other mass-based implementation options (wider trading, allowance allocation to generators), hybrid case (mass-based in Northeast and California, rate-based elsewhere), extended case (further reductions beyond 2030)
- High and low world oil price
- High and low macroeconomic growth
- High and low oil and natural gas resources/technology
- Industrial technology efficiency, high and low technology innovation
- Phase 2 heavy-duty truck requirements
- Extended policies: extends current tax credits and adds follow-on efficiency standards

Key updates in AEO2016

- Incorporation of the U.S. Environmental Protection Agency's final rules for the Clean Power Plan
- Updated renewable capital costs
- Latest California zero-emission vehicle sales mandates, which have been adopted by a number of other states
- Extension of the production tax credit for wind and 30% investment tax credit for solar
- Lower near-term crude oil prices

Key takeaways from the two cases: Electricity

- Implementation of the Clean Power Plan (CPP) using a mass-based approach reduces annual electricity-related carbon dioxide (CO2) emissions to between 1,550 and 1,560 million metric tons (MMT) in the 2030-40 period, substantially below their 2005 and 2015 levels of 2,416 MMT and 1,891 MMT, respectively. Coal's share of total electricity generation, which was 50% in 2005 and 33% in 2015, falls to 21% in 2030 and to 18% in 2040.

- Even without the CPP, electricity-related CO2 emissions remain well below their 2005 level at 1,942 MMT in 2030 and 1,959 MMT in 2040; this outcome reflects both low load growth and generation mix changes driven by the extension of key renewable tax credits, reduced solar photovoltaic (PV) capital costs, and low natural gas prices.

- With the mass-based approach, the strong growth in wind and solar generation spurred by tax credits leads to a short-term decline in natural gas-fired generation between 2015 and 2021. However, natural gas generation then grows significantly under a mass-based CPP implementation, increasing by more than 67% from 2021 through 2040, when it is by far the largest generation source.

Key takeaways from the two cases: Natural Gas and Petroleum

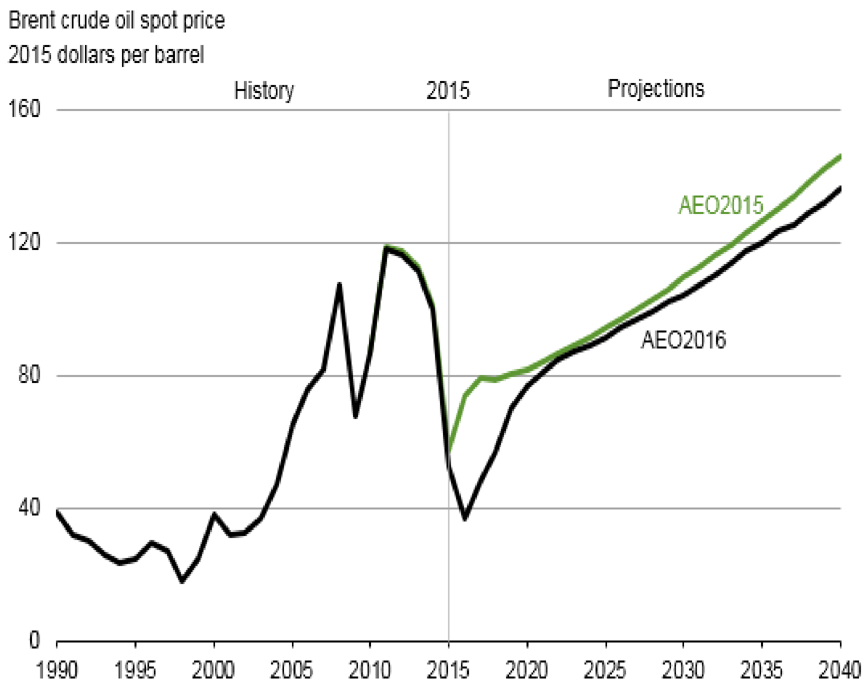
- Natural gas production in the Reference case grows more than 50% between 2015 and 2040. Annual average natural gas prices rise from their 2015 level, $2.62/ million British thermal units (MMBtu) at the benchmark Henry Hub, to roughly $5.00/million Btu in the mid-2020s and remain around that level through 2040. Technology improvements allow natural gas production to rise even as prices stabilize. Gas prices and production are slightly lower without the Clean Power Plan.

- Lower prices keep U.S. crude oil production below 9.5 million barrels per day (b/d) through 2025 in the Reference case; production grows to 11.3 million b/d by 2040, reflecting higher recovery rates driven by technology advances and higher prices. The full AEO2016 will present alternative resource and oil price cases with different implications for production.

- Petroleum use (including natural gas liquids such as ethane and propane) rises 4% from 2015 to 2040 in the Reference case, but transportation use falls 10%, mainly due to improved light duty vehicle (LDV) fuel efficiency; the Reference case does not include proposed Phase 2 standards for heavy-duty trucks or tighter LDV standards beyond 2025, which would further reduce projected oil use in transportation.

Overview

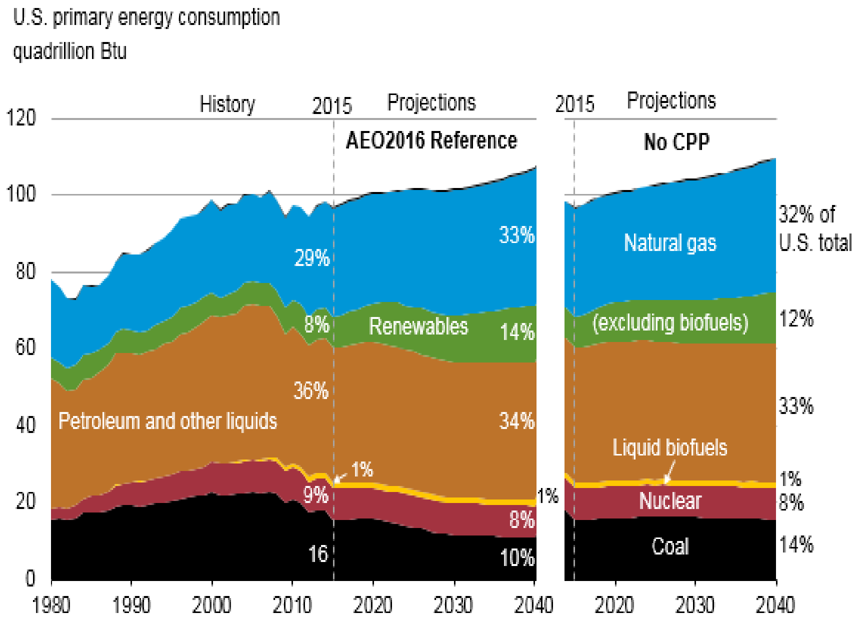
Reference case crude oil price scenario is lower in AEO2016 than in AEO2015, particularly in the near term



Source: EIA, Annual Energy Outlook 2016 Reference case and Annual Energy Outlook 2015 Reference case

- AEO2016 Reference case oil prices are lower than those in last year's outlook, particularly in the near term.
- In the Reference case, the Brent crude oil price averages $37/barrel (b) in 2016, increasing to $77/b in 2020 as demand and supply come into balance. After 2020, the prices continue to rise, as growing demand results in the development of more costly resources.
- The full AEO2016 will explore alternative price and resource/technology paths that reflect the wide uncertainty in future market conditions.

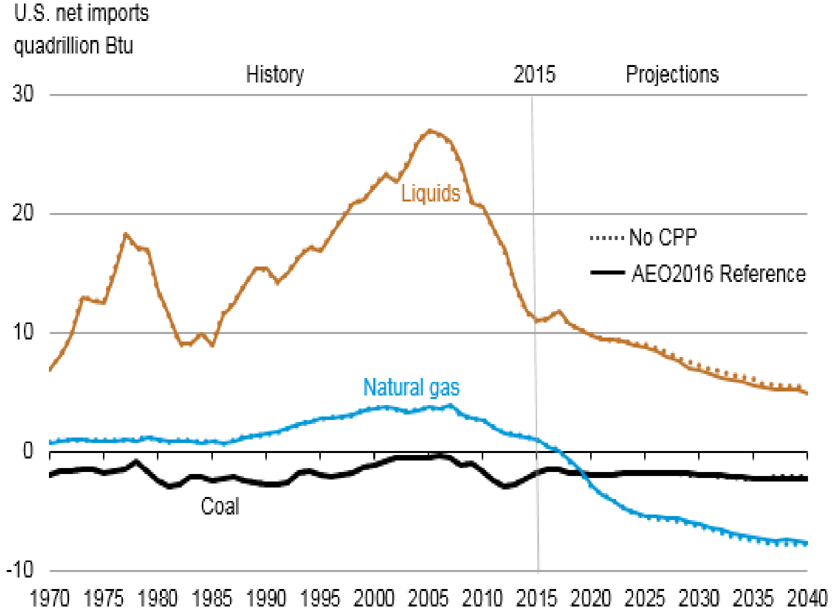
Reductions in energy intensity largely offset impact of gross domestic product (GDP) growth, leading to slow projected growth in energy use



Source: *EIA, Annual Energy Outlook 2016*

- Total U.S. primary energy consumption grows slowly in both cases as reductions in energy intensity offset the impact of GDP growth, with slightly higher growth in the No CPP case than in the Reference case.
- Total petroleum and other liquids consumption increases in the near term but declines from 2020-31 as increases in vehicle fuel economy offset growth in transportation activity and increased industrial use.
- Natural gas use increases throughout the projection period. The No CPP case has slower growth in natural gas use in the electric power sector.
- Coal use in the Reference case declines throughout the projection period, mostly before 2030 because of the Clean Power Plan. In the No CPP case, coal retains a larger market share.
- The renewable share of total energy use (including liquid biofuels) increases, with most of the growth occurring in the electric power sector. Solar and wind account for nearly all of the projected increase.
- Nuclear generation remains close to its current level as the impact of new plant additions is offset by retirements.

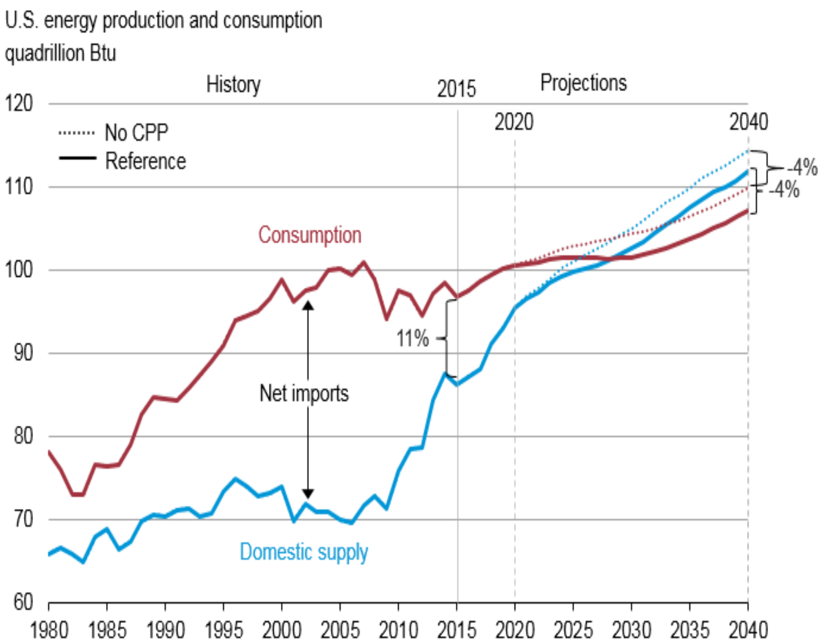
U.S. net energy imports continue to decline (except for liquids in the near term) reflecting increased oil and natural gas production coupled with slowly growing or falling demand



Source: EIA, Annual Energy Outlook 2016

- The share of net imports in total U.S. liquids consumption declines from 60% in 2005 (24% in 2015) to 7% by 2040, which would be its lowest level since 1957.
- The United States becomes a net exporter of natural gas before 2020, largely because of growth in liquefied natural gas exports.
- The United States continues to be a net exporter of coal (including coal coke) over the entire projection.

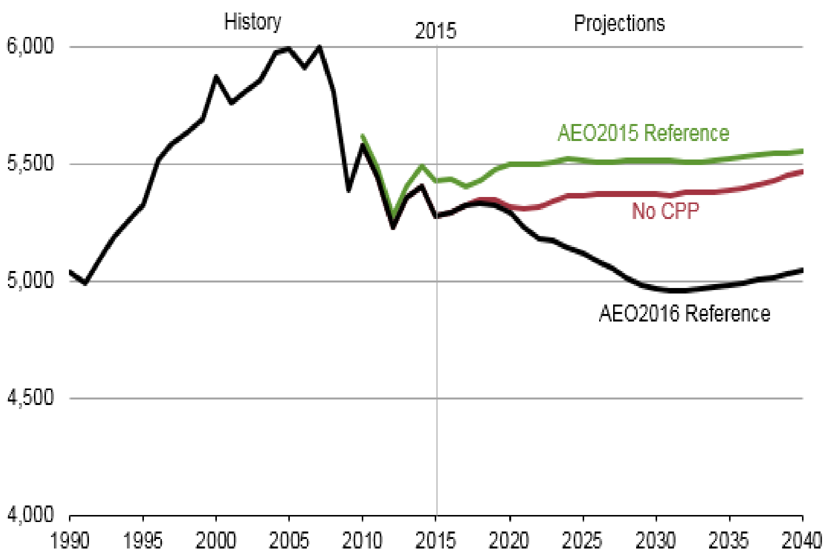
U.S. energy production outstrips consumption, making the United States a net energy exporter



Source: EIA, Annual Energy Outlook 2016

- U.S. net energy imports, including petroleum and other liquids, natural gas, and coal, decline and ultimately end in the Reference case, a first since the 1950s. The net import share of total U.S. energy consumption was 11% in 2015 and 30% as recently as 2005.
- The transition from a net energy importer to a net energy exporter follows a similar pattern in the Reference and No CPP cases, although the total levels of U.S. energy consumption and production are somewhat higher beyond 2022 in the No CPP case.
- By 2040, total U.S. energy production is greater than total U.S. energy consumption, allowing for U.S. net energy exports equal to 4% of total consumption.

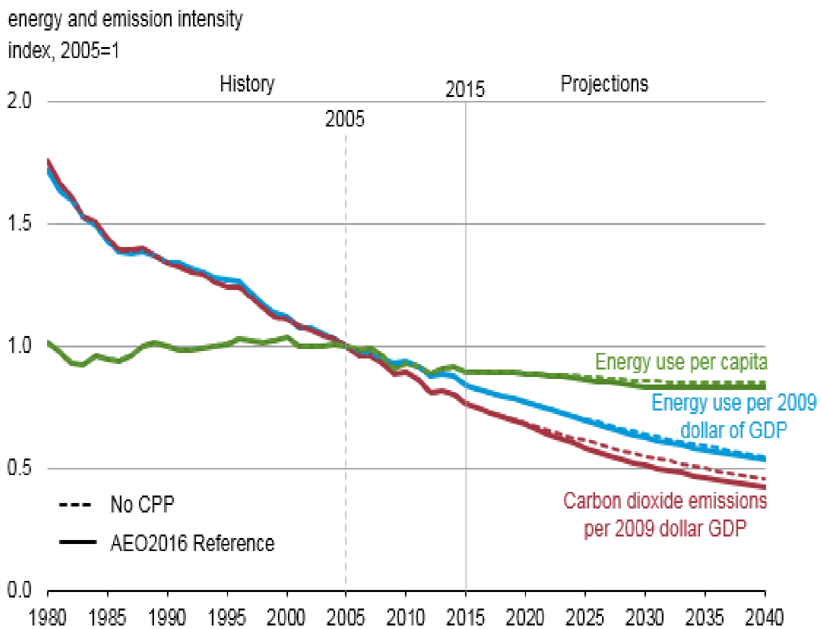
CO2 emissions are lower in AEO2016 Reference case than AEO2015 Reference Case, even without the Clean Power Plan (CPP)



Source: EIA, Annual Energy Outlook 2016

- Key drivers for the lower energy-related CO2 emissions in AEO2016 include:
  - Lower natural gas prices that support higher electricity generation from natural gas with or without the CPP
  - Lower technology costs for wind and solar, combined with extended tax credits and the CPP, and
  - Reduced coal generation as a result of the CPP, which emit the most CO2 per kilowatthour.

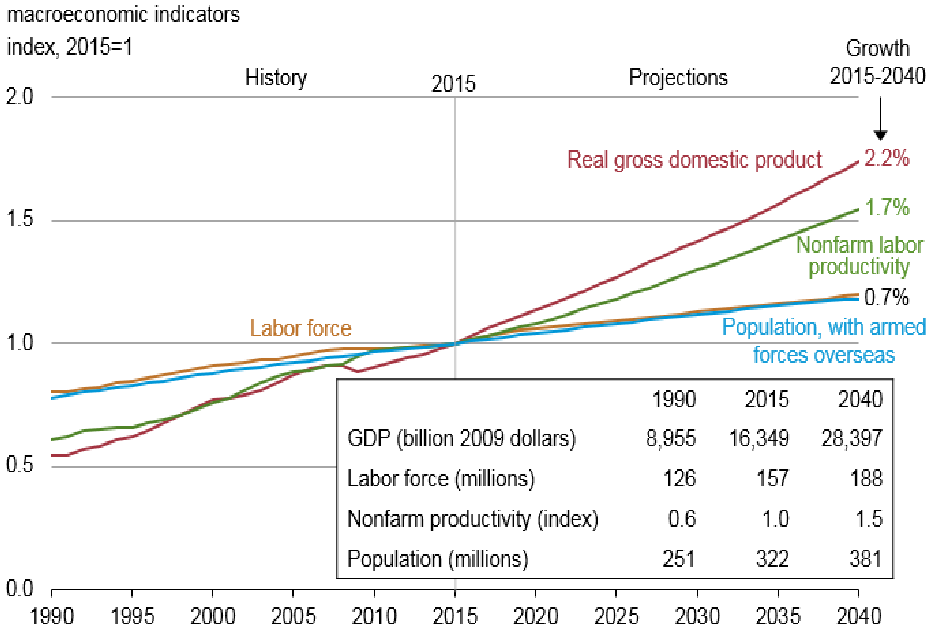
CO2 emissions per dollar of gross domestic product (GDP) decline faster than energy use per dollar of GDP with a shift towards low- and no-carbon fuels



Source: EIA, Annual Energy Outlook 2016 Reference case

- The economy's energy intensity, carbon intensity, and per-capita energy use are projected to decline steadily. In the Reference case, energy use per dollar of GDP declines at an average annual rate of 1.8% over 2015-40, while energy use per capita declines at an average annual rate of 0.3%. With renewables and natural gas providing larger shares of total energy use, CO2 per dollar of GDP declines faster than energy intensity.
- The structure and efficiency of the U.S. economy changes in ways that lower total energy use and energy use per dollar of GDP. The nonindustrial and services sector share of the economy remains near 77% throughout the projection, but there is a shift towards non-energy-intensive industries within manufacturing that is slightly smaller in the absence of the CPP.
- Energy-use-per-capita declines, driven by gains in appliance efficiency, a shift in population from cooler to warmer regions, and an increase in vehicle efficiency standards, combined with modest growth in travel per licensed driver.

Productivity improvements are the main driver of growth in Gross Domestic Product (GDP) with the labor force showing similar growth to the Reference case



	1990	2015	2040
GDP (billion 2009 dollars)	8,955	16,349	28,397
Labor force (millions)	126	157	188
Nonfarm productivity (index)	0.6	1.0	1.5
Population (millions)	251	322	381

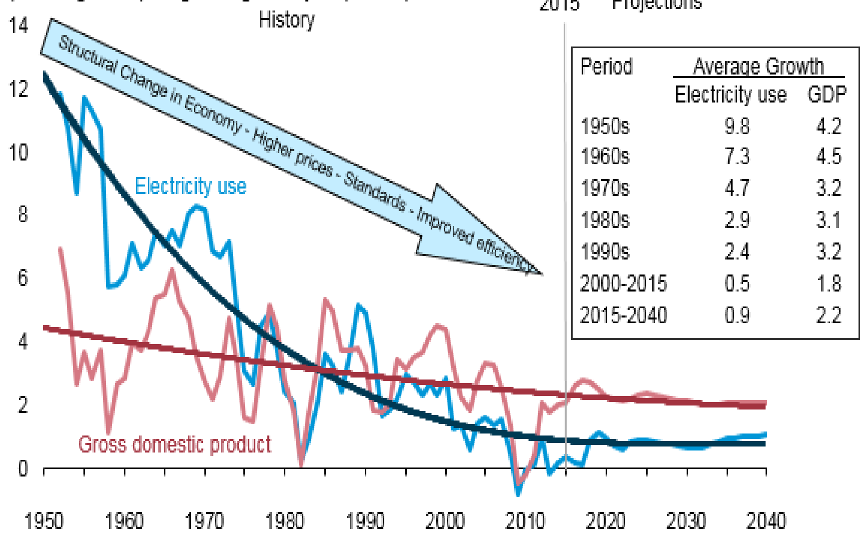
Source: EIA, *Annual Energy Outlook 2016*

- Economic growth depends mainly on growth and productivity in the labor force. Population growth determines labor force growth in the long run.
- In the Reference case, the labor force grows by an average of 0.7%/year. Labor productivity in the nonfarm business sector grows by 1.7%/year; and growth in real GDP averages 2.2%/year.
- Investment growth averages 2.8%/year in the Reference case, disposable income available to households grows by 2.3%/year, and disposable income per capita increases by 1.7%/year.

Electricity

Electricity use (including direct use) is expected to continue to grow, but the rate of growth slows over time as it has almost continuously over the past 60 years

U.S. electricity use and GDP
percent growth (rolling average of 3-year periods)

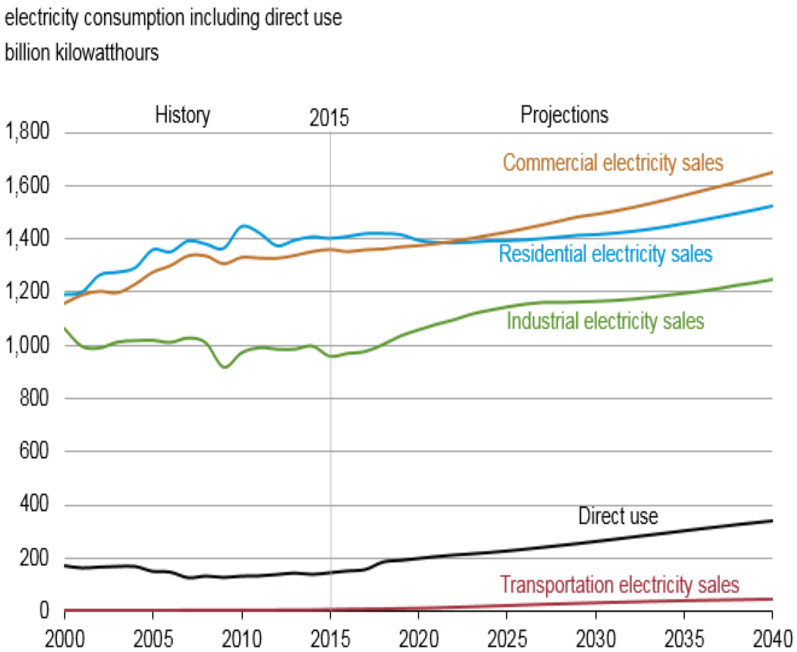


Period	Average Growth: Electricity use	Average Growth: GDP
1950s	9.8	4.2
1960s	7.3	4.5
1970s	4.7	3.2
1980s	2.9	3.1
1990s	2.4	3.2
2000-2015	0.5	1.8
2015-2040	0.9	2.2

Source: EIA, Annual Energy Outlook 2016

- Growth in the economy and electricity demand remain linked, but the linkage is shifting toward much slower electricity demand growth relative to economic growth.
- The factors driving this trend include slowing population growth, near market saturation of key electricity using appliances, improving efficiency of nearly all equipment and appliances in response to standards and technological change, and a shift in the economy toward less energy-intensive industries.
- Efficiency standards for lighting and other appliances that have been established over the past few years continue to put downward pressure on growth in electricity demand as new equipment is added and the existing stock is replaced.

Industrial activity bolsters growth in projected electricity consumption relative to recent history



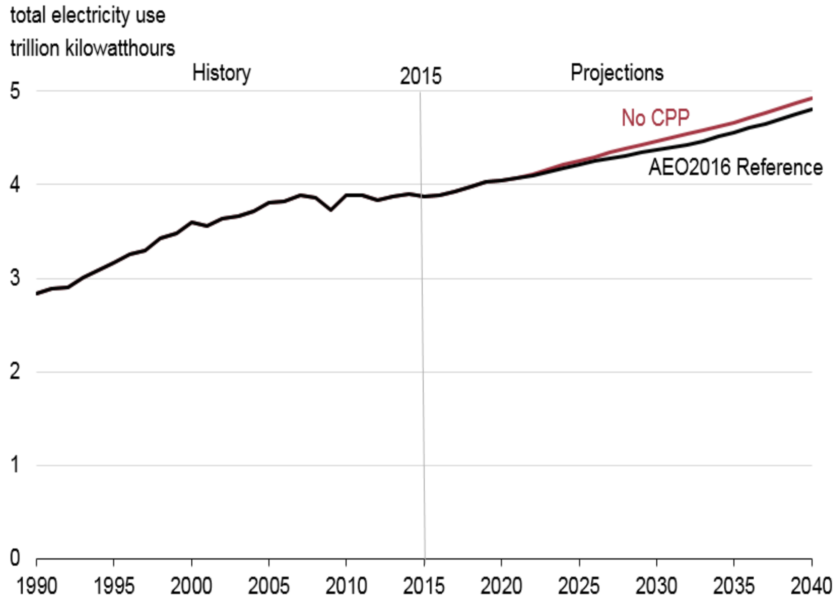
Source: EIA, *Annual Energy Outlook 2016*

- Electricity sales grow 0.7%/year on average from 2015-40 in the Reference case – similar to 0.6% growth from 2000-2015.
- Electricity consumption – including direct use (or generation for own use) – is projected to grow 0.9% on average in the Reference case, faster than the 0.5% growth from 2000-2015.
- Generation for direct use declined 1.4%/year from 2000-2015. End-use generation for direct use grows 3.8%/year on average between 2015-40 in the Reference case, bolstered by adoption of rooftop photovoltaic (PV) and natural gas-fired combined heat and power (CHP).
- Industrial electricity sales declined 0.7%/year between 2000 and 2015, which were affected by a decline in shipments during the recession. Industrial electricity sales grow 1.1%/year from 2015-40 with an expected increase in industrial activity.
- Residential electricity sales grew 1.1%/year from 2000 and 2015. In the Reference case, residential sales grow just 0.3%/year. Efficiency improvements, especially in lighting and PV adoption, offset most of the effects of sector growth, increased use for space cooling, and miscellaneous electric loads (MELs).
- Commercial electricity sales also grew 1.1%/year from 2000-2015. Commercial sales are projected to grow 0.8%/year from 2015-40 in the Reference case. Efficiency improvements, especially in lighting and refrigeration, and increased adoption of PV and commercial CHP, partially offset increased electricity use for computer servers and for MELs.

Clean Power Plan (CPP) implementation in the AEO2016 Reference case

- CPP compliance is met through imposing mass-based caps at the Electricity Market Module (EMM) region level, using aggregated targets based on U.S. Environmental Protection Agency (EPA) state budgets covering existing and new sources.
  - EMM region enforcement implicitly assumes trading can occur between states within an EMM region, but no allowance trading between regions is allowed in the Reference case
  - Using budgets that cover new sources satisfies EPA's requirement that leakage - through shifting electricity generation to new fossil fuel sources - does not occur.
- Reference case assumes that allowances are allocated to load entities and that revenues from allowance sales are used to provide rebates on consumer's electricity bills.

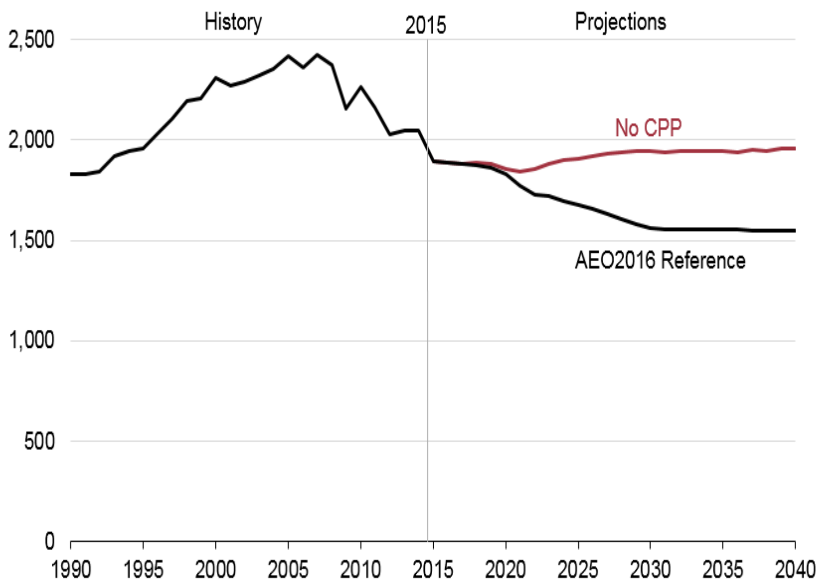
Electric demand is 2% lower in 2030 in the Reference case than in the No CPP case, reflecting both compliance actions and higher prices with the Clean Power Plan (CPP)



Source: EIA, Annual Energy Outlook 2016

- Reference case projections reflect several types of efficiency improvements related to CPP implementation.
  - Subsidies, in the form of direct rebates, decrease the installed capital cost of energy-efficient equipment, as is typical of utility incentives.
  - EIA assumes that energy efficiency portfolios vary by Census division in terms of the implementation, timing, and level of end-use subsidies.
- Residential demand grows 9% in the Reference case and 11% in the No CPP case over 2015-40. Low residential demand growth in both cases reflects continued efficiency improvements in appliances and electronics.
- Commercial demand grows 21% in the Reference case and 26% in the No CPP case over the same period, with the difference reflecting both CPP-driven energy efficiency programs and electricity prices.
- Industrial demand grows 30% in the Reference case and 32% in the No CPP case over 2015-40. Lower demand growth in the Reference case reflects higher electricity prices and not because of specific CPP-related efficiency gains.

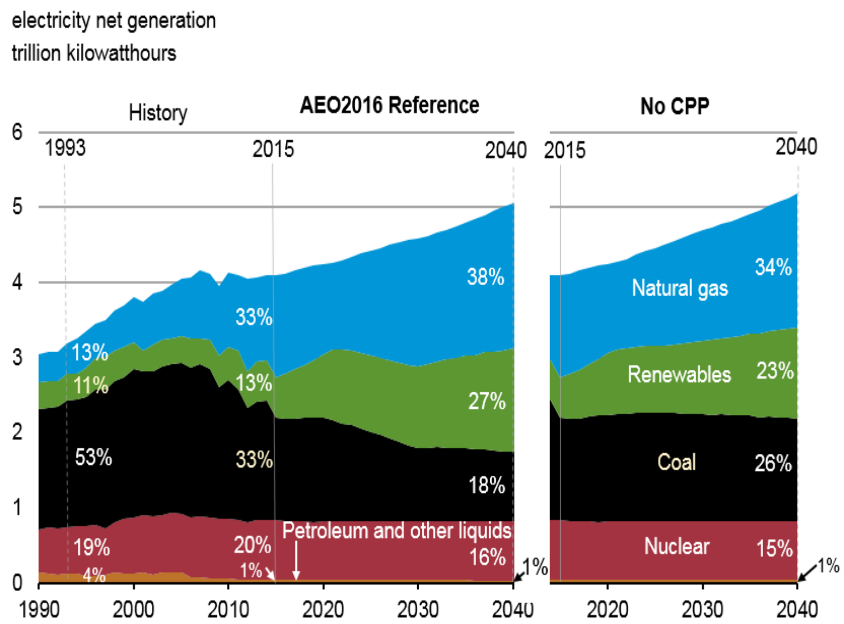
Clean Power Plan (CPP) lowers total electric sector carbon dioxide (CO2) emissions by an additional 20% over the No CPP case by 2030



Source: EIA, Annual Energy Outlook 2016

- Electric power sector CO2 emissions declined over the past decade as a result of shifts to less carbon-intensive generation sources. Low natural gas prices, state-level renewable portfolio standards, and federal tax credits for renewables have led to the increased use of those generating sources, while tighter environmental regulations have discouraged coal use.
- In the Reference case, CO2 emissions in the power sector were 35% below 2005 levels in 2030 due to the implementation of the CPP. The Reference case assumes implementation through mass-based standards, which remain in place at 2030 levels throughout the remainder of the projection, resulting in flat power sector emissions. The full AEO2016 release will include other CPP implementation cases.
- In the No CPP case, emissions rise slightly over the projection, but remain at least 19% below 2005 levels in all years. There are fewer coal retirements than in the Reference case, but any incremental demand growth is generally met with new natural gas or renewable capacity, limiting emissions growth.

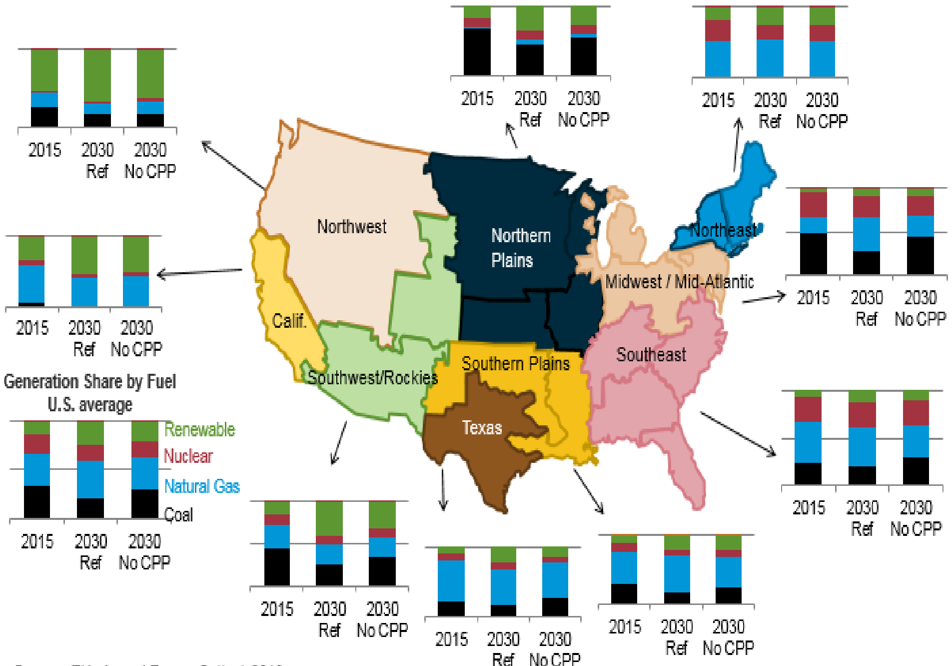
Clean Power Plan (CPP) accelerates shift to lower-carbon options for generation, led by growth in renewables and gas-fired generation; results are sensitive to CPP implementation approach



Source: *EIA, Annual Energy Outlook 2016*

- Substantial growth in the renewable generation share of total electricity generation occurs with or without the Clean Power Plan (CPP), with renewable generation more than doubling from 2015 levels in both cases. Lower costs, particularly for solar installations, are a big driver of the renewable growth, along with tax credit extensions and state-level renewable mandates.
- The natural gas share grows more substantially in the Reference case than in the No CPP case, as natural gas is used to replace retiring coal generation as a way to comply with the CPP. Natural gas generation increases by 44% in the Reference case and by 32% in the No CPP case from 2015 to 2040.
- Coal generation declines by 32% from 2015 to 2040 in the Reference case, as a result of retirements and lower levels of utilization to meet the carbon dioxide emissions caps. In the No CPP case, coal generation levels remain flat, as fewer units are retired and the remaining units are assumed to operate at higher levels, particularly as natural gas prices rise. However, the coal share of total generation still declines, and virtually no new capacity is added.
- Nuclear generation levels remain flat throughout the projection, with new units offset by retirements. High construction costs result in a projection that no new, unplanned, nuclear plants will be constructed even with the CPP in place, and the nuclear share of total generation declines from the 2015 level in both cases.

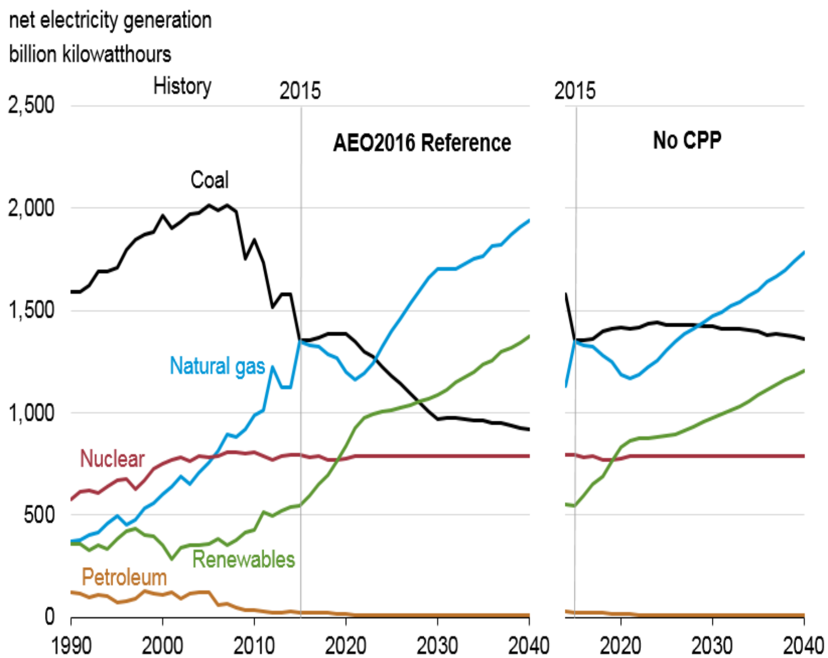
The electricity generation mix varies widely across U.S. regions, which is likely to affect both compliance choices and costs



Source: EIA, *Annual Energy Outlook 2016*

- In 2015, coal generation is used most heavily to meet electricity demand in the Southwest/Rockies, Midwest/Mid-Atlantic, and Northern Plains regions of the country. These regions will require the largest shifts in generation mix for Clean Power Plan (CPP) compliance.
- The Midwest/Mid-Atlantic region increasingly turns to increased use of natural gas in the Reference case, whereas the Northern Plains and Southwest/Rockies take advantage of abundant, low-cost renewable resources in response to the CPP.
- Without the CPP, the Northern Plains and Southwest/Rockies still increase renewable generation, but to a lesser extent, as fewer coal plants are retired and the coal generation share does not drop as dramatically.
- Regions that are currently dominated by natural gas or renewable generation continue to use those resources with or without the CPP.

Natural gas generation falls through 2021; both gas and renewable generation surpass coal by 2030 in the Reference case, but only natural gas does so in the No CPP case



Source: *EIA, Annual Energy Outlook 2016*

- Although coal and natural gas generation were roughly equal in 2015, rising natural gas prices in the near term and significant growth in renewables spurred by the production tax credit and investment tax credit result in declining natural gas generation over the next few years.
- However, the combination of the Clean Power Plan (CPP) and relatively low natural gas prices results in natural gas and renewables permanently surpassing coal generation by the mid- and late-2020s, respectively.
- The No CPP case results in fewer generating unit retirements and flat coal generation through the projection period. In this case, natural gas generation surpasses coal generation in the late-2020s. Total renewables generation grows steadily, but remains below coal generation through 2040 in the No CPP case.
- Coal's share of the generation mix has also been reduced by the growing role of renewables other than hydroelectric power, especially wind and solar. Until recently, increased use of nonhydro renewables has largely been driven by a combination of state and federal policies. Declining capital costs for both technologies are also improving their competitiveness.

The Clean Power Plan (CPP) results in large declines in coal generation; the mass-based implementation of the CPP in the Reference Case increases natural gas generation and adds to growth in renewable generation beyond the early 2020s

change in generation from 2015 to 2030
billion kilowatthours

	AEO2016 Reference				No CPP			
Region	Coal	Natural Gas	Nuclear	Renewables	Coal	Natural Gas	Nuclear	Renewables
Midwest /Mid-Atlantic	-197	201	-33	30	-22	88	-33	26
Northern Plains	-68	12	1	85	4	14	1	65
Southern Plains	-40	49	-1	44	-10	5	-1	45
Southwest/Rockies	-39	-1	0	73	-13	5	0	56
Northwest	-21	-6	0	60	-18	2	0	47
Texas	-11	16	0	62	31	16	0	25
California	-9	0	0	76	-9	6	0	67
Northeast	0	20	-13	24	-1	8	-13	24
Southeast	2	62	38	85	103	-22	38	69
US total	-382	354	-9	542	67	123	-9	427

Generation change from 2015-2030

Decreasing | No Change | Increasing

Source: *EIA, Annual Energy Outlook 2016*

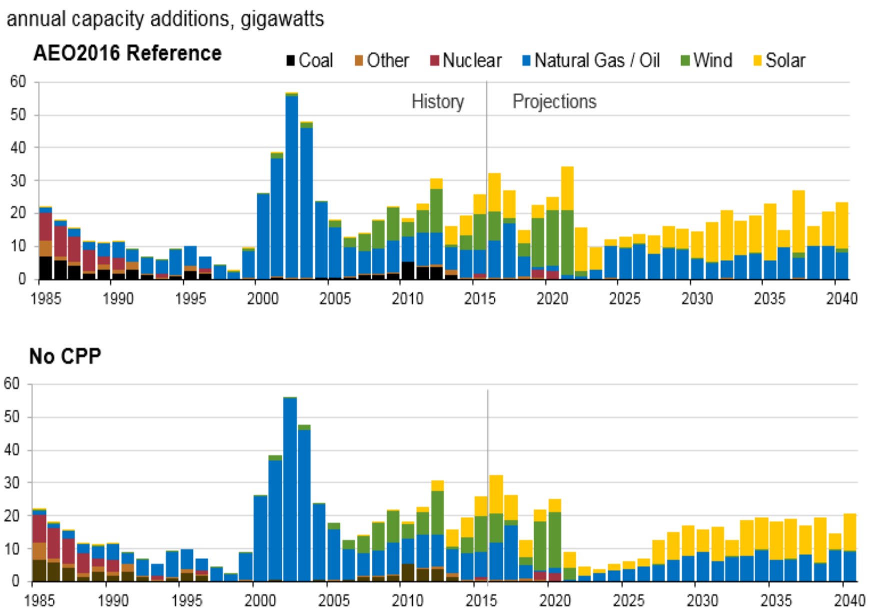
- Renewable energy plays a significant role in meeting electricity demand growth throughout most of the country, irrespective of the CPP. In the Reference case, renewable generation accounts for 27% of total U.S. generation in 2040. Even without the pressure to reduce emissions, renewable generation provides 23% of total U.S. generation in 2040 in the No CPP case.

- The largest changes in generation mix occur in regions where coal-fired generation has played a significant role in the past, including the Midwest/Mid-Atlantic, Southern Plains, and Southeastern regions. For the Midwest/Mid-Atlantic and Southern regions, there is a strong increase in natural gas generation in the No CPP and Reference cases in 2030, reinforcing the current trend already underway of natural gas generation replacing coal generation.

- In the Northern Plains states, the coal displaced by the CPP is replaced by increased renewables generation, with a cumulative addition of 85 billion kilowatthours (kWh) in the Reference case by 2030, compared with 65 billion kWh in the No CPP case.

- Two coastal regions, the Northeast and California, show little change between the Reference and No CPP cases in 2030, largely due to the impact of existing programs that result in emission reductions similar to those needed to comply with the CPP in both cases.

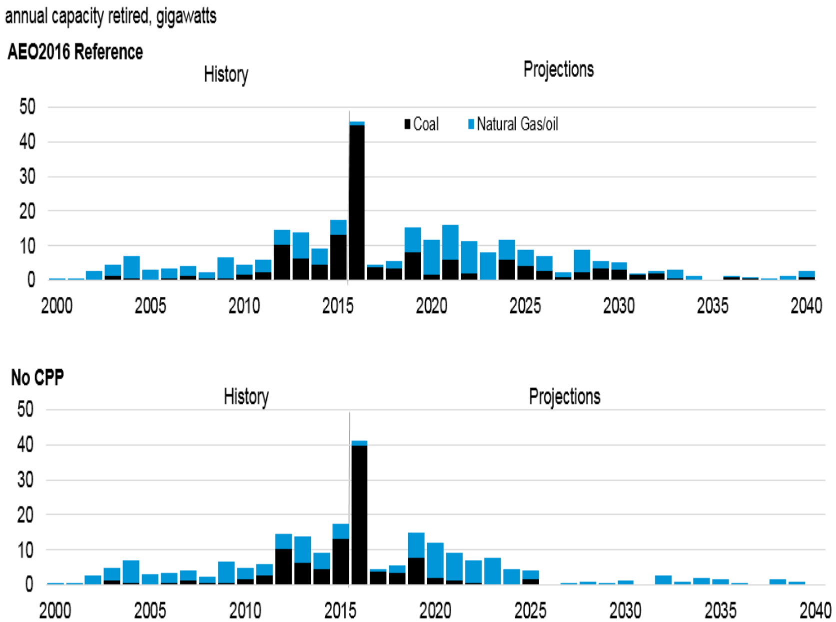
Lower costs and extension of renewable tax credits boost projected additions of wind and solar capacity prior to the 2022 effective date of the Clean Power Plan (CPP)



Source: *EIA, Annual Energy Outlook 2016*

- In the Reference case, which includes the CPP, 112 gigawatts (GW) of new wind and solar capacity is added in the years from 2016 through 2021. After 2021, natural gas capacity is also added to meet the CPP requirements.
- Continued coal retirements under the CPP support a consistent market for new capacity throughout the projection period.
- Without the CPP, the tax-credit-driven increase in renewable capacity supplants the need for new capacity from 2020-25 with relatively flat electricity demand growth.
- After 2030, new generation capacity additions are split primarily between solar and natural gas, with solar capacity representing 60% of new capacity additions in the Reference case and 56% in the No CPP case.
- The non-expiring 10% investment tax credit for solar projects, combined with continued capital cost reductions, encourages new solar capacity. Wind projects receive a phased-out production tax credit that can only be claimed by plants under construction before 2020.

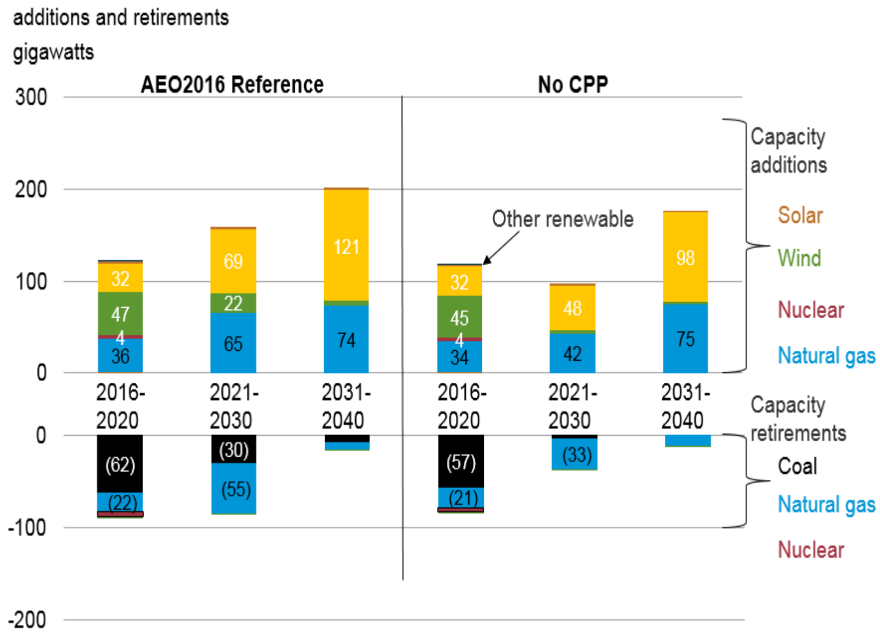
The Mercury and Air Toxics Standards (MATS) and low natural gas prices are the main near-term drivers of coal plant retirements; Clean Power Plan (CPP) increases near-term coal plant retirements modestly and adds more retirements in later years



Source: EIA, *Annual Energy Outlook 2016*

- In both the Reference and No CPP cases, compliance with the MATS drives coal plant retirements in the near term, with 40–45 gigawatts (GW) of coal retirements in 2016.
- Additional coal and natural gas/oil capacity is retired in the longer term to comply with CPP-related emission reductions targets for existing fossil-fired plants. An additional 55 GW of coal-fired capacity is retired after 2016 in the Reference case, compared with 21 GW in the No CPP case.
- Total coal and natural gas/oil retirements between 2016 and 2040 are 184 GW in the Reference case, more than the 126 GW of retirements in the No CPP case.

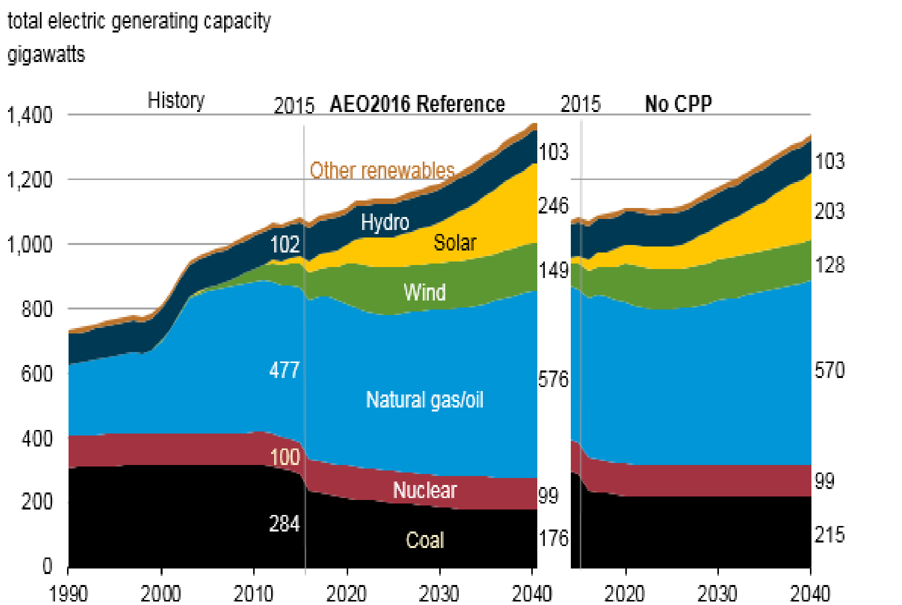
The Clean Power Plan (CPP) results in higher levels of both natural gas and renewable capacity, replacing additional coal retirements and reduced utilization of coal plants



Source: *EIA, Annual Energy Outlook 2016*

- The Reference case adds 477 gigawatts (GW) of natural gas and renewable capacity over the projection period compared to 386 GW in the No CPP case, as higher levels of low/no emission capacity are required to replace retiring fossil plants to comply with the CPP.
- While initial coal generating unit retirements are similar and driven by the Mercury Air Toxics Standards in each case, an additional 53 GW of fossil-fired generating unit retirements from 2021-40 occur in the Reference case compared to the No CPP case.
- Overall capacity additions from 2021-40 are higher in the Reference case, 361 GW compared to 274 GW, as increased retirements and lower output from existing fossil plants create demand for new capacity.
- Wind and solar capacity additions are driven by tax credit extensions and declining costs in both the Reference case and the No CPP case.

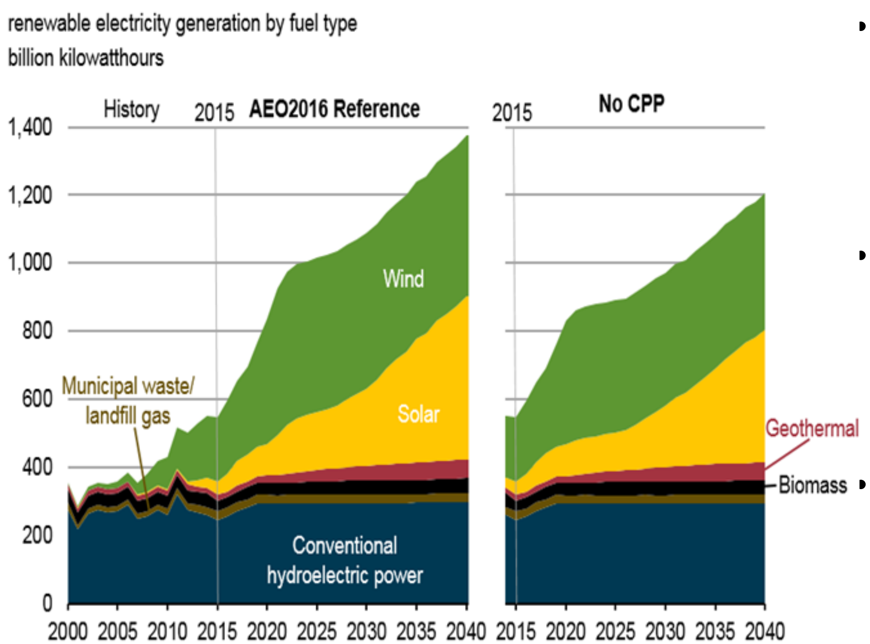
Reference case projects slightly higher levels of total capacity because of higher levels of renewable capacity



Notes: prior to 2000 wind and solar data are not broken out, and is reflected in 'Other Renewable'; Hydro includes pumped storage
Source: EIA, Annual Energy Outlook 2016

- Although total electricity sales in 2040 is 2.7% lower in the Reference case than in the No CPP case, overall capacity additions are 2.5% higher in the No CPP case, as solar and wind capacity make up a larger share of total capacity. These technologies do not provide the same contribution to system reliability as coal, nuclear, or natural gas units, so more overall capacity must be built to maintain planning and operating reserve margins.
- Natural gas/oil capacity grows in both cases, reflecting the net impact of retired oil and natural gas-fired steam plants and new natural gas-fired (primarily combined-cycle plant) additions.
- Nuclear capacity is unchanged across the cases, as higher construction costs prevent nuclear expansion from being competitive even with the Clean Power Plan. The total nuclear capacity is virtually unchanged from 2015 levels, but reflects the net impact of planned additions and retirements occurring by 2020, which offset each other.

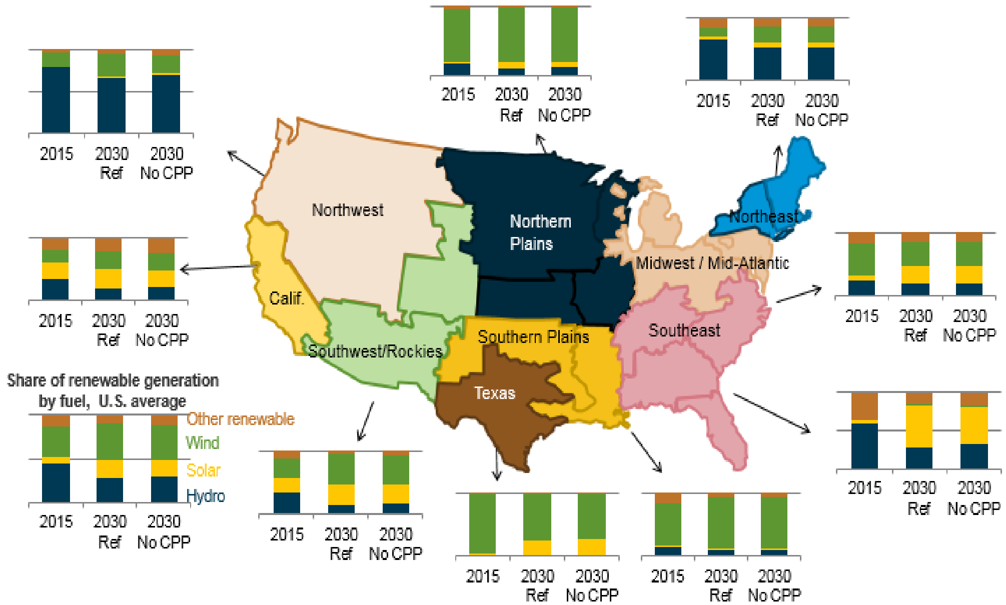
Changing tax and cost assumptions contribute to stronger solar growth, with the Clean Power Plan (CPP) providing a boost to renewables



Source: EIA, Annual Energy Outlook 2016

- In the Reference case, wind generation grows nearly 150% over 2015-40. In the No CPP case, it grows 110%, over the same period. Growth in wind generation slows after 2022 due to the tapering of the production tax credit.
- Solar generation grows by nearly 12-fold over 2015-40 in the Reference case. Even without the CPP, reduced solar costs and extended tax credits result in a 9-fold growth in solar generation over that period.
- Electricity from conventional hydroelectric power, municipal waste and landfill gas, biomass, and geothermal vary little between the Reference case and the No CPP case.

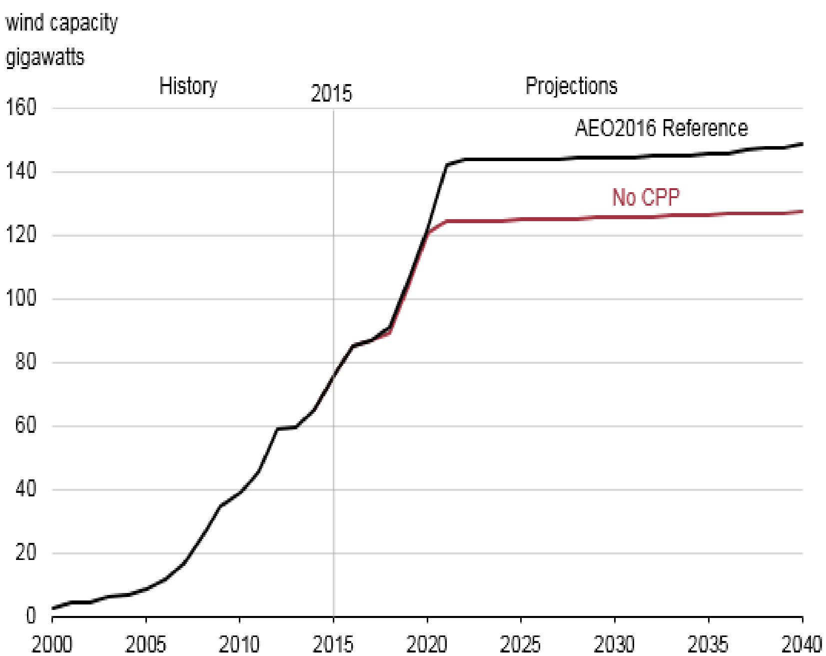
Generation from renewables varies across U.S. regions; hydro loses overall share as wind and solar generation increase by 2030



Source: *EIA, Annual Energy Outlook 2016*

- In California, where renewable portfolio standard policies and market factors are already favorable to renewables, generation from renewables in the Reference and No CPP cases is similar.
- Regions where wind energy is currently the dominant source of renewable generation, like the Northern Plains, Southern Plains, and Texas, maintain high levels of wind generation in both the Reference and No CPP cases through 2030. In the Northern and Southern Plains in 2030, solar generation increases from 2015 levels, taking market share from hydro and other renewables. By 2030, increases in solar allow it to gain share in Texas.
- In the Northwest, where hydro is the dominant renewable, hydro generation in 2030 is virtually identical in the Reference and No CPP cases. However, the hydro share of total renewable generation declines over 2015-30, as the share of wind generation increases.

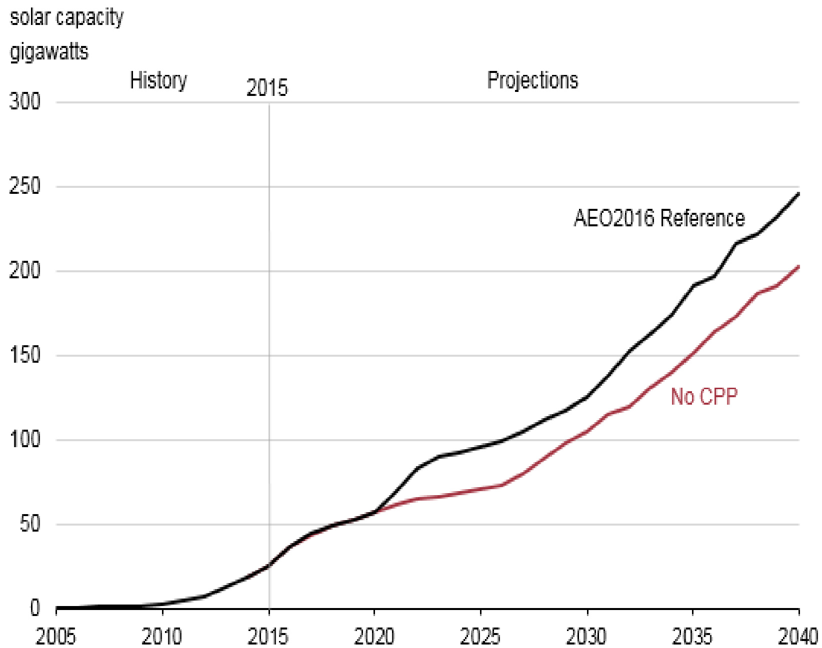
Wind capacity is 15% higher in the AEO2016 Reference case than in the No CPP case from 2022-40



Source: EIA, Annual Energy Outlook 2016

- Wind capacity increases in both the AEO2016 Reference and No CPP cases between 2015 and 2020, when the production tax credit (PTC) is still available to plants that begin construction prior to the phase-down of these credits.
- With the CPP, this growth continues through 2022 as projects that began construction prior to the final PTC expiration come online.
- Although wind capacity continues to increase through 2040, it grows at a slower rate in the absence of tax credits and with increasing need to access sites further from existing electric transmission lines or with less-favorable development characteristics.

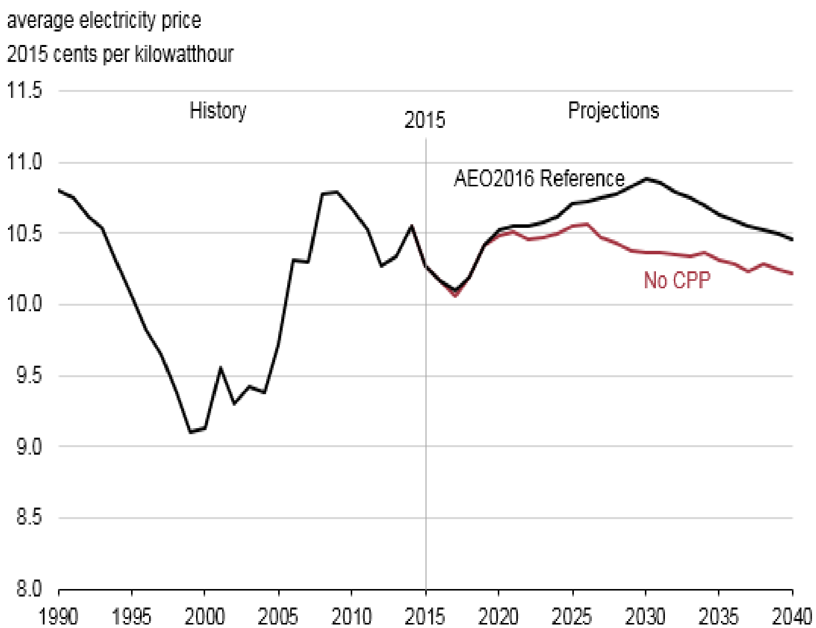
Solar capacity is 20% higher in the Reference case than in the No CPP case by 2030



Source: *EIA, Annual Energy Outlook 2016*

- Solar capacity increases throughout the projection. In addition to the effects of investment tax credits, state policies, and the Clean Power Plan (CPP), the cost of solar has declined significantly in recent years, making it increasingly economic, even without the CPP.
- Solar capacity is added at a relatively steady pace over 2015-40, in both the Reference, which includes the CPP, and the No CPP cases. The CPP increases the need to reduce fossil-fired generation to comply with emissions limits.
- Because solar is added at a faster rate than wind, solar capacity is projected to surpass wind capacity by 2032 in the Reference case and by 2033 in the No CPP case. All capacity comparisons include end-use technologies, with growth in the residential, commercial, and utility sectors. End-use solar photovoltaic installations represent 36% of 2040 solar capacity in the Reference case, and 42% in the No CPP case.

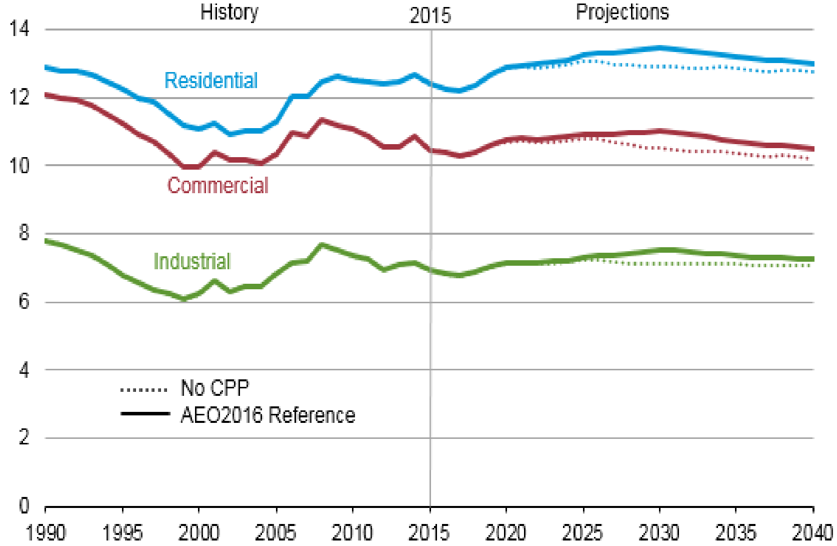
Reference case electricity prices average 3% above the No CPP case from 2025-30; this result may vary with different Clean Power Plan (CPP) implementation approaches



Source: *EIA, Annual Energy Outlook 2016*

- Electricity prices in many regions move with natural gas prices and availability, especially as natural gas generation increases relative to other fuels throughout the projection period.
- In the Reference case, which includes mass-based implementation of the CPP, generators that emit CO2 must obtain allowances from the companies that distribute electricity. Higher generation costs are partially offset when the distribution companies that receive allowance payments pass the savings on to consumers through lower distribution rates.
- In the Reference case, electricity prices are most affected by the increase in clean generation builds and efficiency improvements between 2025 and 2030. Retail prices average 3% higher from 2025-30 in the Reference case than in the No CPP case.
- Total U.S. electricity expenditures are 1.3% higher in the Reference case than in the No CPP case over this same period, as higher prices and above-baseline efficiency improvements through CPP programs decrease electricity usage.
- Price and expenditure projections are dependent on assumed implementation strategies; both would be higher to the extent that the full value of allowances in a mass-based implementation is not rebated to ratepayers.

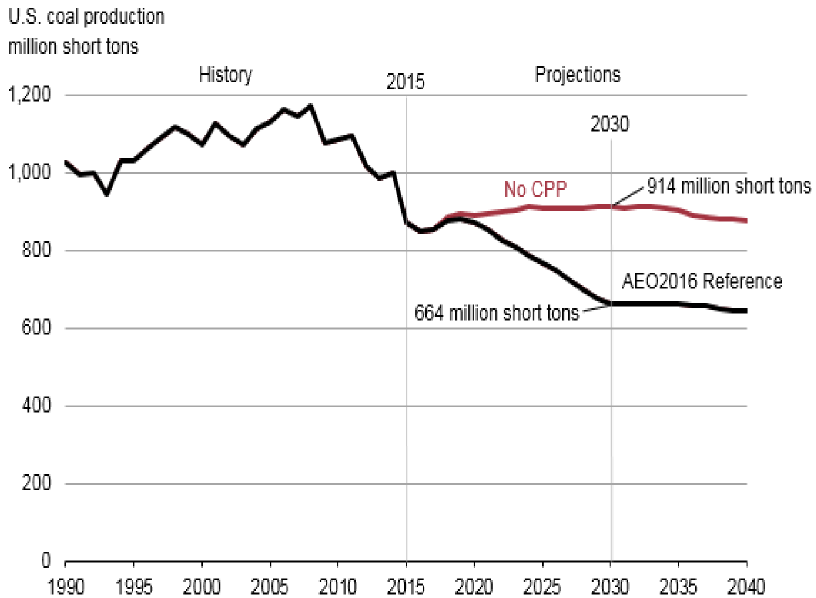
Electricity prices increase with rising fuel costs and expenditures for electric transmission and distribution infrastructure



Source: EIA, Annual Energy Outlook 2016

- Residential and commercial electricity prices are significantly higher than industrial prices; this mainly reflects the higher costs of distribution services for residential and commercial customers.
- Prices for all customer classes rise over 2015-30 in part due to higher transmission and distribution costs.
- Prices in the Reference case are somewhat higher than those the No CPP case for all customer classes; price differences between cases tend to be largest over the 2025-30 time period.

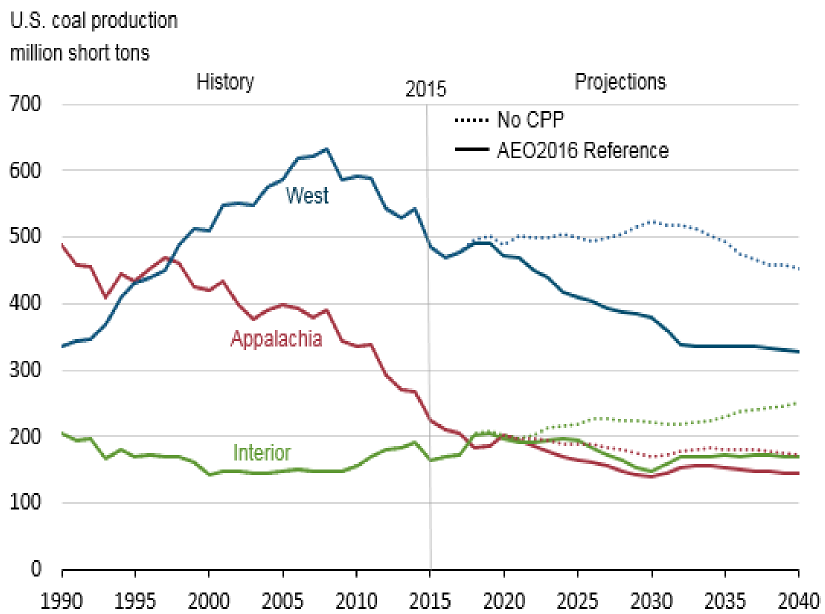
Reference case U.S. coal production in 2030 is 27% below its level in the No CPP case



Source: EIA, Annual Energy Outlook 2016

- In the Reference case, total coal production falls from about 870 million short tons in 2015 to 830 million short tons in 2022, as coal supply reacts to the onset of the Clean Power Plan (CPP) and falls further to 640 million tons by 2040.
- Compared with the No CPP case, coal production is 250 million short tons lower in 2030 in the Reference case. After 2030, the difference between the cases is largely maintained through 2040.
- Even without the CPP, near-term coal plant retirements, competitive natural gas prices, and renewables expansion continue to limit a recovery in the coal mining industry. Coal production changes little through 2040 in the No CPP case.

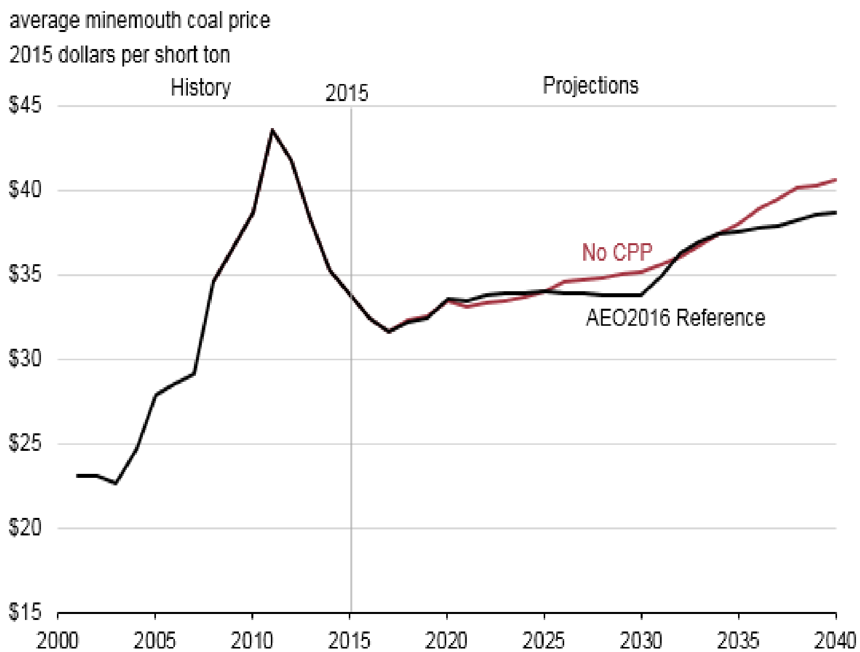
Regional coal production is 17%-32% lower in the Reference case by 2040 than in the No CPP case



Source: EIA, *Annual Energy Outlook 2016*

- In the AEO2016 Reference case, the West region accounts for 58% and 53% of the total decline in production in 2030 and 2040, respectively, when compared with the No CPP case. Significant amounts of coal capacity are retired in states that are large consumers of western coal --Texas, Indiana, Illinois, Michigan, and Wisconsin.
- In the Reference case, Interior coal production declines after 2019, while it increases in the No CPP case. Unlike the West and Appalachia, in the No CPP case, higher sulfur coal production in the Interior region is expands by 2040 as coal power plants without emission control equipment are forced to retrofit to comply with the Mercury Air Toxics Standards, which takes effect in 2015-16.
- About 60% of Appalachian coal is currently consumed in the power sector. The decrease in Appalachian coal production in the Reference case compared to the No CPP case is relatively small, as plant retirements and interfuel competition reduce the role of Appalachian coal in the power sector down regardless of Clean Power Plan (CPP) implementation. In the Reference case, Appalachian coal production is increasingly dependent on exports, which account for about 67% of Appalachian production in 2040.

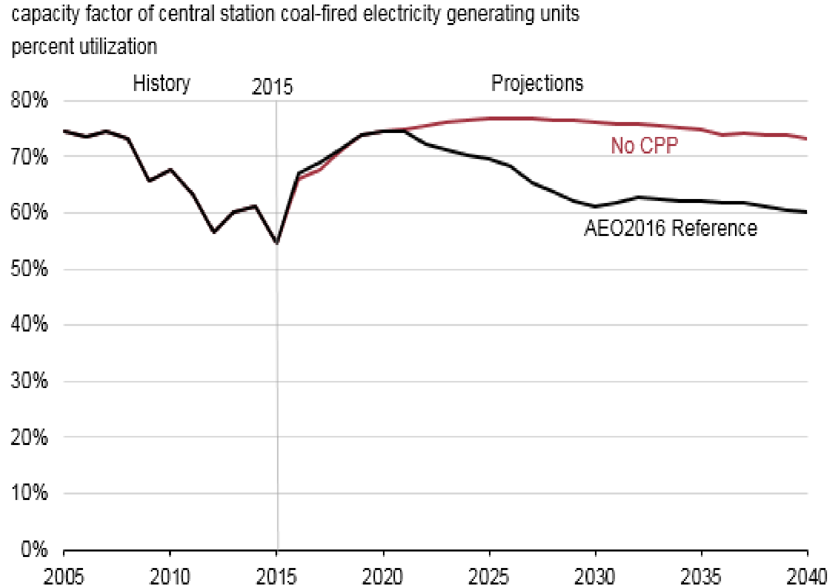
Average minemouth coal prices are 4% higher in 2030 and 5% higher in 2040 in the No CPP case than in the AEO2016 Reference case



Source: EIA, Annual Energy Outlook 2016

- In the Reference case, average minemouth coal prices are mostly lower than in the No CPP case primarily because of lower coal production, which restrains coal prices as the least efficient, most-costly mines close.
- The average minemouth coal price over 2017-30 changes little in the Reference case as the effects of lower average coal mine productivity, which tends to raise production costs, and declining coal demand, which tends to lower minemouth coal prices, are largely offsetting.
- After 2030, falling mine productivity overwhelms the impact of declining demand and the minemouth coal price increases.

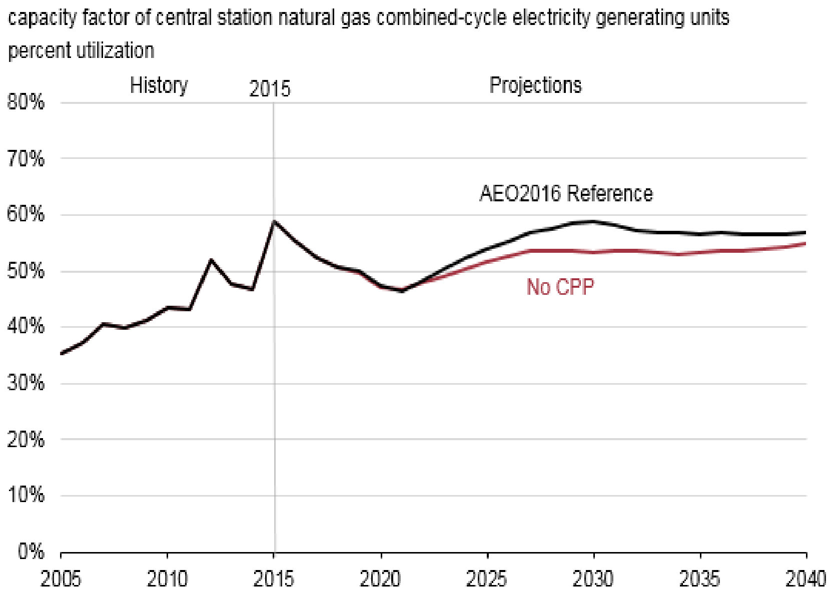
Average capacity factor for coal-fired generating units falls by 15 percentage points by 2030 in the Reference case when compared with the No CPP case



Source: *EIA, Annual Energy Outlook 2016*

- In the Reference case, the average capacity utilization rate for coal-fired plants, which was 55% in 2015, is significantly below that level in the No CPP case. This outcome occurs as a result of increased penetration of renewables such as solar and wind and increasing utilization rates of lower-carbon natural gas-fired combined cycle plants.
- In the No CPP case, the average coal-fired capacity utilization rate increases to almost 75% in 2020 due to the retirement of lower-performing coal plants and moderately increasing natural gas prices. After 2020, the average capacity utilization rate remains fairly constant in the No CPP case as existing coal plants remain cost-competitive with natural gas-fired combined cycle plants given the relative fuel prices.

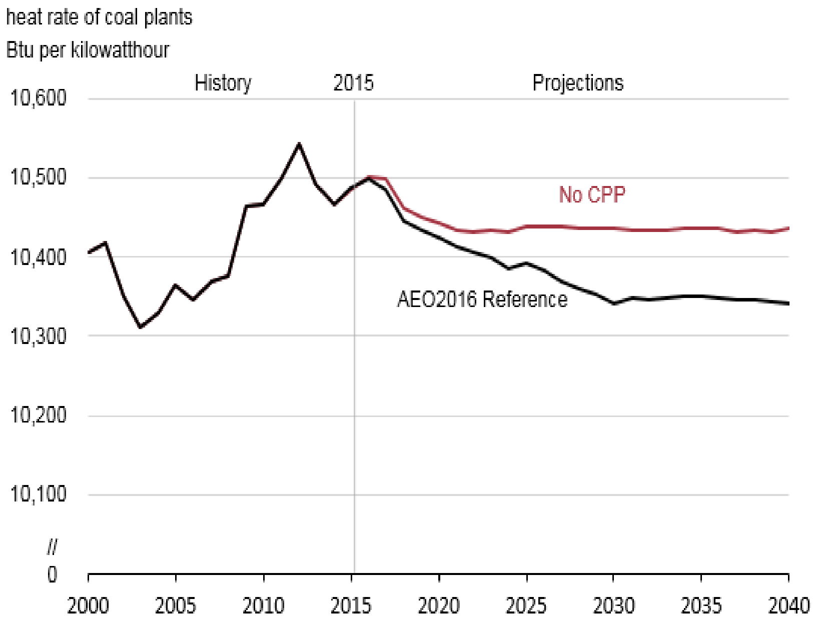
Average capacity factor for gas-fired combined cycle units rises by 5 percentage points by 2030 in the Reference case when compared with the No CPP case



Source: EIA, *Annual Energy Outlook 2016*

- In 2015, the average capacity factor for natural gas-fired combined-cycle plants approached 60%, exceeding the corresponding rate for coal-fired capacity for the first time.
- The utilization rate for gas-fired combined-cycle capacity declines over the next 5 or 6 years, primarily as a result of increased generation from renewable technologies.
- Utilization rates for gas-fired capacity start to rise in the early 2020s, when tax credits for renewable technologies are reduced (solar photovoltaics) or eliminated (wind), and the Clean Power Plan encourages higher utilization of natural gas-fired combined-cycle plants as one of the main compliance strategies for reducing generation from carbon-intensive coal-fired plants, thereby, lowering emissions.
- When compared with the No CPP case, capacity factors of natural gas-fired combined-cycle plants in the Reference case increase by less than 1 percentage point in 2022, when the CPP emissions standards are first implemented, and by 5 percentage points in 2030.

Heat rates for coal-fired plants are up to 1% lower due to heat rate improvement and retirements in Reference case than in the No CPP case

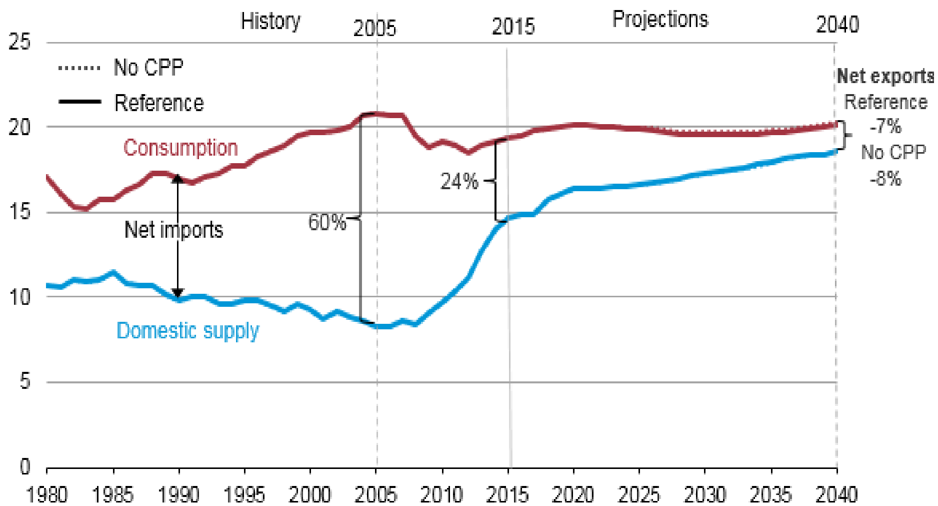


Source: *EIA, Annual Energy Outlook 2016*

- Operating efficiencies (fuel input per unit of output) for power plants are represented by heat rates. Reducing heat rates lowers fuel consumption and the corresponding fuel costs and emissions.
- The average heat rate for coal-fired capacity in 2015 is about 10,500 British thermal units per kilowatthour (kWh). In the Reference case, the average heat rate declines by about 0.5% by 2020 and continues to decline thereafter.
- The improved efficiency is due to 60 gigawatts (GW) of retirements (22% of current power-sector coal capacity), generally reflecting less efficient units in the current fleet, and to a lesser extent the 12 GW that are invested in heat rate improvements (4% of current power-sector coal capacity).
- The Clean Power Plan further reduces the average heat rate of coal-fired plants beyond 2022 with 40 GW of coal-fired additional retirements and 3 GW of coal-fired capacity that undertake heat rate improvements.

Petroleum and other liquid supply

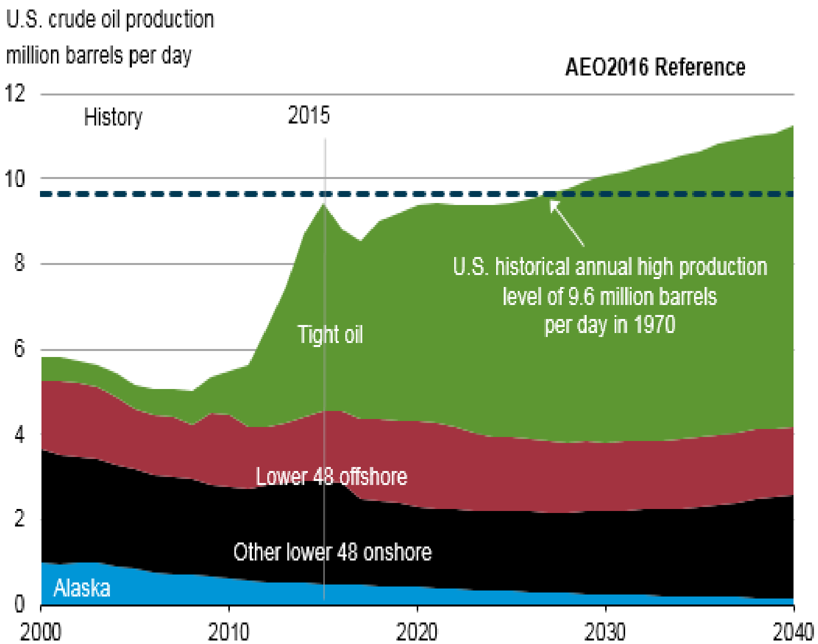
U.S. liquids production grows under Reference case price and resource/technology assumptions; the net import share declines with stagnant consumption



Source: EIA, Annual Energy Outlook 2016

- Domestic production of petroleum and other liquids grows from current levels as crude oil prices rebound.
- Total consumption of petroleum and other liquids remains relatively level in volumetric terms in the Reference case, as decreases in transportation consumption offset increases in industrial consumption.
- The import share of total consumption dropped sharply between 2005 and 2015, from 60% to 24%, and continues to drop after 2017, to just over 7% in 2040, when the United States imports 1.5 million barrels/day.

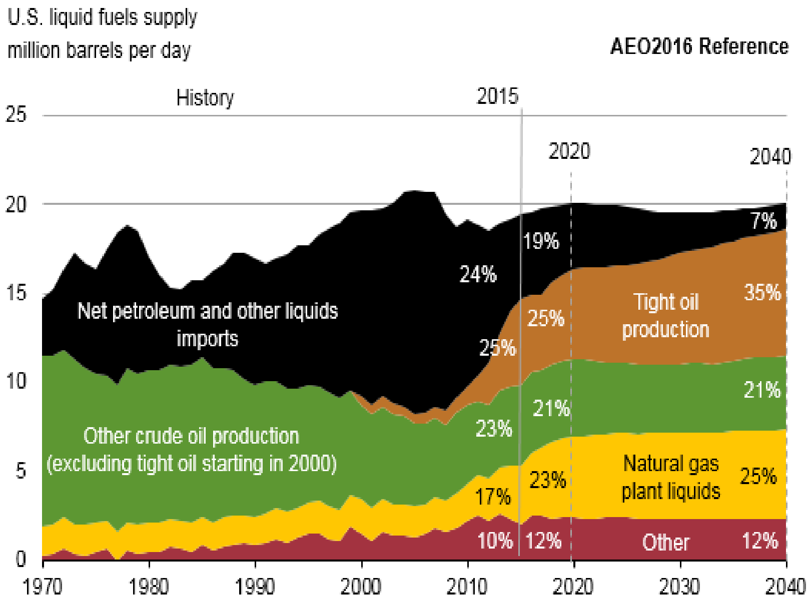
U.S. crude oil production rises above previous historical highs before 2030 in both cases; cases in AEO that use alternative price and resource /technology assumptions could be quite different



Source: EIA, Annual Energy Outlook 2016

- U.S. crude oil production drops from 9.4 million barrels/day (b/d) in 2015 to 8.6 million b/d in 2017 (mainly in response to declines in crude oil prices), before growing through 2040 to reach 11.3 million b/d in the Reference case.
- Lower prices through 2017 has the greatest impact on tight oil production, which drops to 4.2 million b/d in 2017 before increasing to 7.1 million b/d in 2040. The general increase in tight oil production is largely attributed to the higher oil prices and the ongoing exploration and development programs that expand operator knowledge about producing reservoirs.
- In the offshore Lower 48 states, offshore production is less sensitive to short-term price movements than onshore production. Lower 48 offshore crude oil production is estimated to increase to 2.0 million b/d in 2021. After 2021, Lower 48 offshore crude oil production declines to roughly 1.6 million b/d in 2030 and averages close to that level through 2040.
- Both onshore and offshore production in Alaska continues to decline through 2040, dropping from nearly 0.5 million b/d in 2014 to under 0.2 million b/d in 2040.

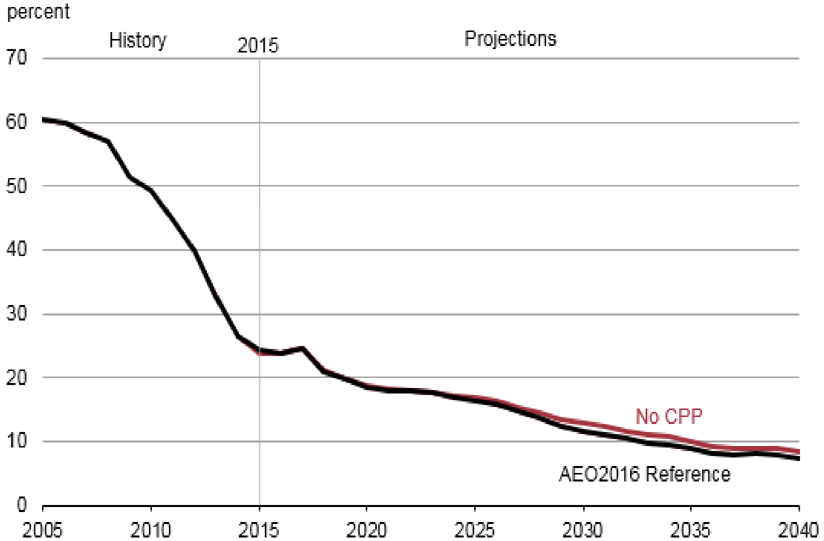
Combination of increased tight oil production and higher fuel efficiency drives projected decline in oil imports



Note: "Other" includes refinery gain, biofuels production, all stock withdrawals, and other domestic sources of liquid fuels
Source: EIA, Annual Energy Outlook 2016

- There are two main sources of future liquid fuels production growth: tight oil and natural gas plant liquids.
- In the Reference case, tight oil production increases after 2017 to 7.1 million barrels/day (b/d) in 2040, increasing from 25% of total U.S. liquid fuels supply in 2015 to 35% in 2040.
- Natural gas plant liquids production increases from 3.3 million b/d in 2015 to 4.8 million b/d in 2025 and reaches 5.0 million b/d in 2040.

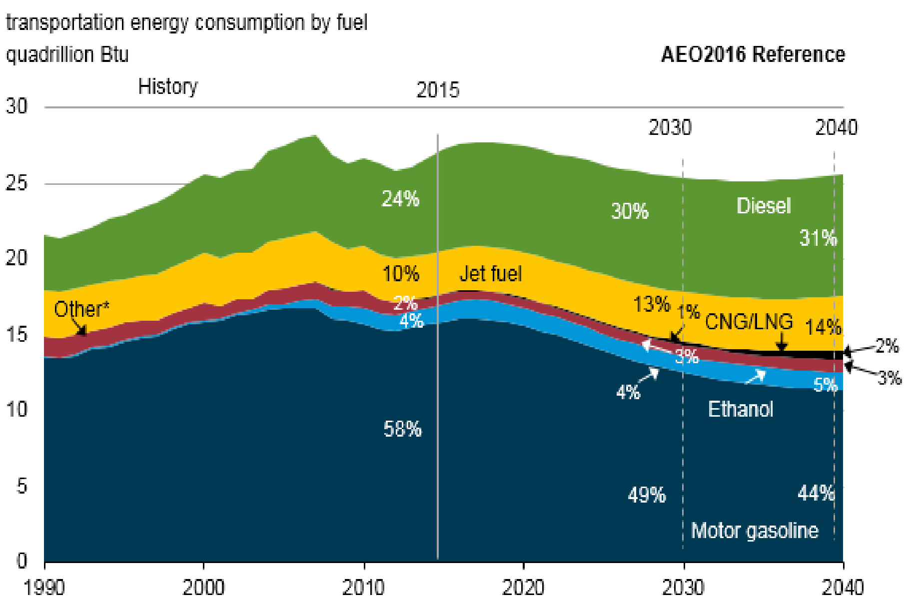
Net imports provide a declining share of U.S. supply; AEO cases with alternative price and resource/technology assumptions will differ



Source: *EIA, Annual Energy Outlook 2016*

- In the Reference case, lower levels of domestic consumption of liquid fuels and higher levels of domestic production of crude oil push the net import share of crude oil and petroleum products supplied down from 24% in 2015 to 7% in 2040.
- The growth in net imports as a share of liquids consumption over 2015-17 reflects the reaction of U.S. production price declines since mid-2014.
- After 2017, the increase in crude oil prices lifts domestic production, which against the backdrop of generally flat consumption, results in the continued decline of the share of liquid fuels provided by net imports.

In the transportation sector, motor gasoline use declines; diesel fuel, jet fuel, and natural gas use all grow

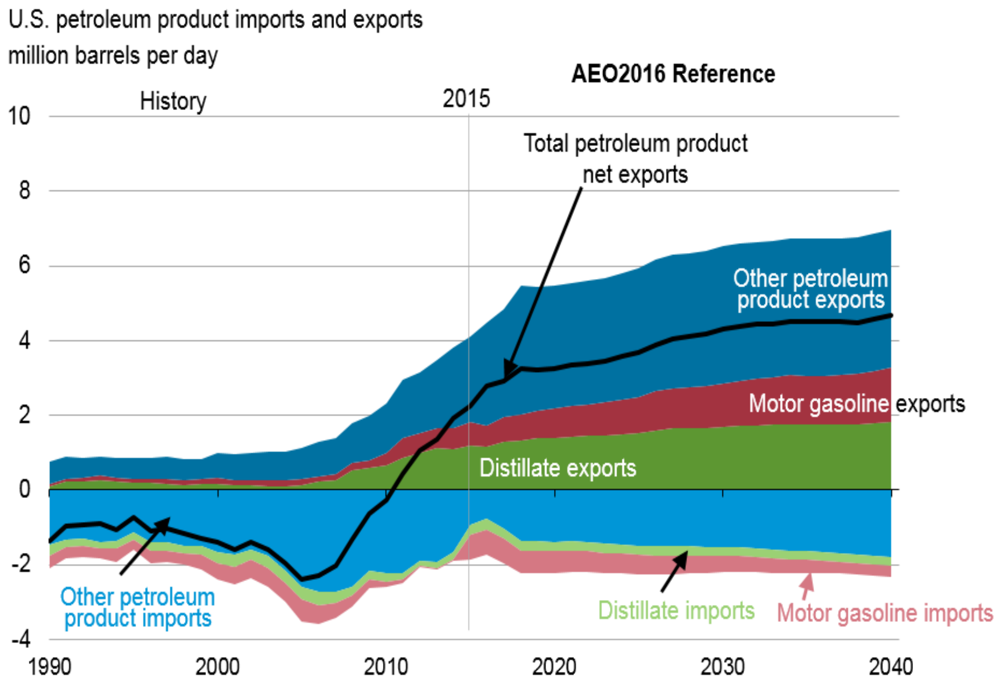


Source: EIA, Annual Energy Outlook 2016

*Includes aviation gasoline, propane, residual fuel oil, lubricants, electricity, and liquid hydrogen

- Transportation sector total delivered energy consumption (excluding pipeline) declines over 2015-40 in the Reference case. This trend differs markedly from history, which saw 1.3% average annual growth over 1973-2007 (2007 was the peak year for consumption).
- Petroleum-based gasoline use falls 26.3% over 2015-40, driven by rising light-duty vehicle fuel economy.
- Use of all other transportation fuels grows over 2015-40, led by diesel fuel and compressed and liquefied natural gas. Proposed Phase 2 fuel economy standards for heavy-duty trucks are not included in the Reference case; but will be considered in an alternative case included in the full AEO2016.
- The majority of energy consumed in the transportation sector by the end of the projection is still in the movement of people (mostly motor gasoline and jet fuel), although personal travel demand across modes grows more slowly than historically, while energy efficiency improves at a greater rate than historically. Energy consumed in the movement of goods (mostly diesel and natural gas) grows faster than for personal travel due to robust travel demand and moderate efficiency gains.

U.S. net exports of petroleum products continue to grow



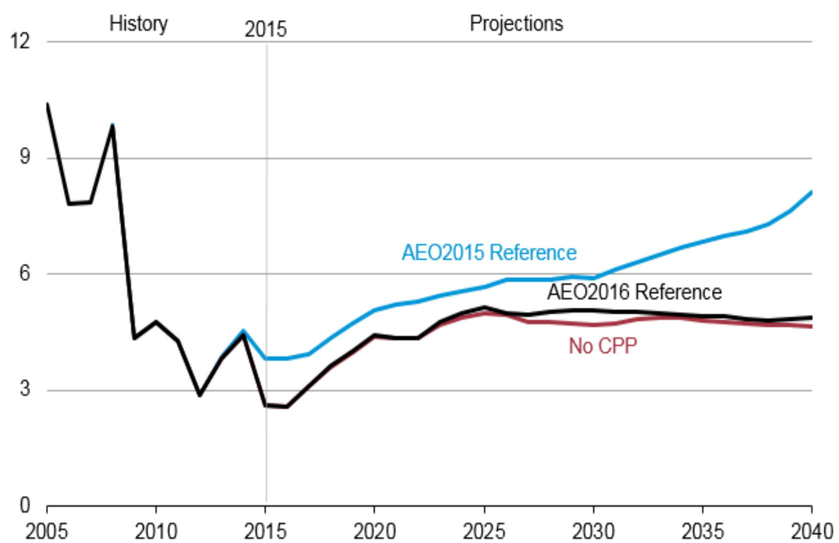
Source: *EIA, Annual Energy Outlook 2016*

- Total petroleum product exports (primarily gasoline, diesel, and HGL, among others), which were fairly consistent, at about 800 thousand barrels/day (b/d) over 1990-2008, increased rapidly over 2008-15, reaching about 4.1 million b/d in 2015.
- Total petroleum product exports, particularly of distillates and HGL, continue to grow in the reference case, as generally increasing domestic crude oil and natural gas liquids production and low natural gas prices support continued favorable economics of U.S. petroleum product supply.

Natural gas

Natural gas prices are projected to remain below $5 per million British thermal units through most of the projection period with or without the Clean Power Plan

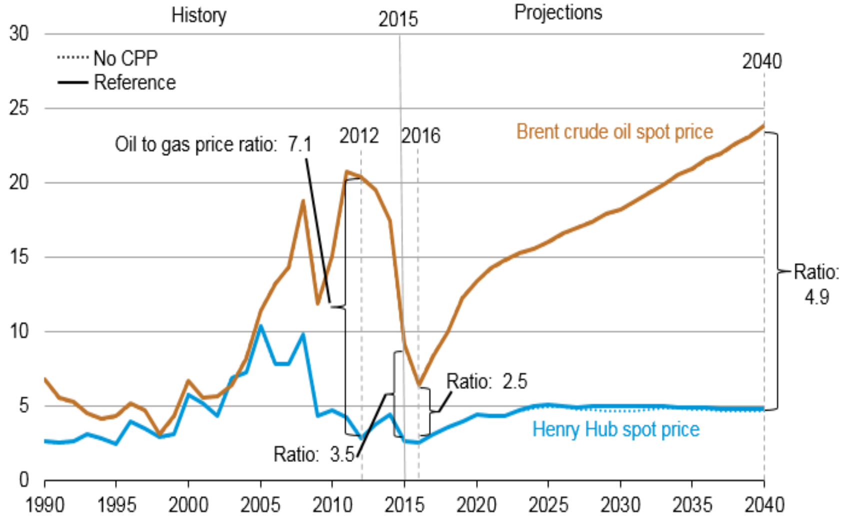
average Henry Hub spot prices for natural gas
2015 dollars per million Btu



Source: EIA, Annual Energy Outlook 2016

- The Henry Hub spot price for natural gas averaged \$2.62/million Btu in 2015, the lowest annual average price since 1995. Despite the low price in 2015, production gains continued as a result of abundant domestic resources and improved production technologies.
- U.S. natural gas prices are expected to rebound from 2015 levels, rising above \$4.40/million Btu by 2020 (an average increase of 11% annually).
- Growth in demand for natural gas, notably for liquefied natural gas (LNG) exports from projects that are already under construction, results in upward pressure on prices.
- Over 2020-40, production, end-use consumption in the industrial and electric power sectors, and exports of LNG are projected to increase. However, technology improvements, which result in drilling cost declines and increased recovery rates, allow productive capacity to keep pace with demand, resulting in stable prices throughout much of the projection.
- Average annual U.S. natural gas prices at the Henry Hub over 2022-40 are lower in the No CPP case than in the Reference case. The lower prices in the No CPP case reflect less demand for natural gas and higher use of coal to generate electricity.

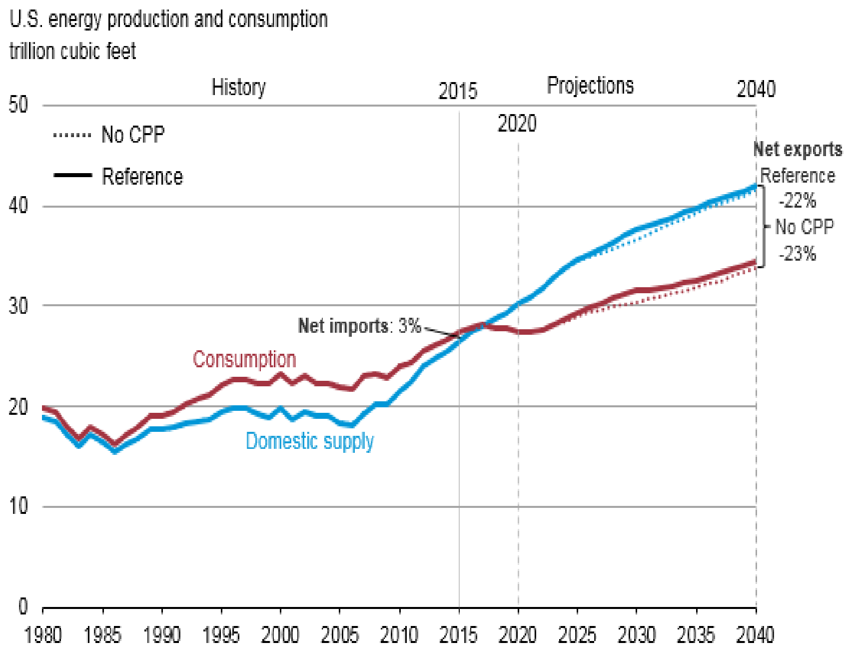
Difference between U.S. natural gas prices and crude oil prices grows through 2040



Source: EIA, Annual Energy Outlook 2016

- The ratio of oil-to-natural-gas prices is defined in terms of the Brent crude oil price and the Henry Hub spot natural gas price on an energy-equivalent basis. A 1:1 ratio indicates that crude oil and natural gas cost the same in terms of energy content.
- While this ratio has decreased considerably in recent years, the differential grows through the projection period.
- The oil-to-gas price ratio peaked in 2012 at 7.1, with low natural gas prices (the result of abundant domestic supply and weak winter demand) and high oil prices. The ratio fell to 3.5 in 2015, driven by a decline in oil prices. In 2016, the ratio will fall further to 2.5 with a further decline in oil prices.
- From 2016-20 both oil and gas prices see their greatest growth. After 2020, oil prices continue to grow, at a slower pace, while natural gas prices hold steady (driven by continued improvements in extraction technologies).
- U.S. natural gas prices are determined largely on a regional basis in response to supply and demand conditions in North America, although increasing liquefied natural gas exports put some upward pressure on the domestic natural gas price. Oil prices are more responsive to global supply and demand.

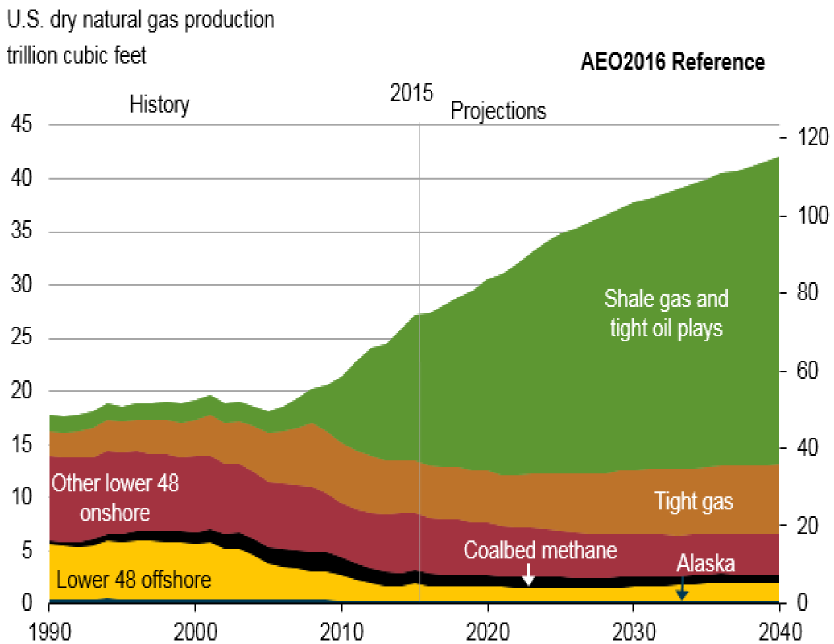
U.S. natural gas production exceeds consumption, making the United States a net exporter of natural gas in the very near future



Source: *EIA, Annual Energy Outlook 2016*

- The growth in natural gas production is driven by the continued development of shale gas resources where technology improvements result in higher rates of recovery at lower costs throughout the projection period. Natural gas production increases at an average annual rate of 1.8% over 2015-40.
- Production growth holds down natural gas prices, stimulating demand for U.S. natural gas in the United States (particularly in the electric power sector) and in overseas markets.
- Total U.S. natural gas consumption grows by 0.9%/year from 2015-40, but decreases between 2017-21 due to a decline in the electric power sector where natural gas use drops by 1.4 trillion cubic feet (Tcf). After 2021, U.S. natural gas consumption rises steadily.
- The United States transitions from being a net importer of 1.0 Tcf of natural gas in 2015, or 3% of U.S. total natural gas supply, to a net exporter by 2018. Almost 50% (3.6 Tcf) of the growth in net exports that occurs by 2021 is liquefied natural gas exports. Net U.S. exports of natural gas reach 7.5 Tcf in 2040, or 18% of total production.

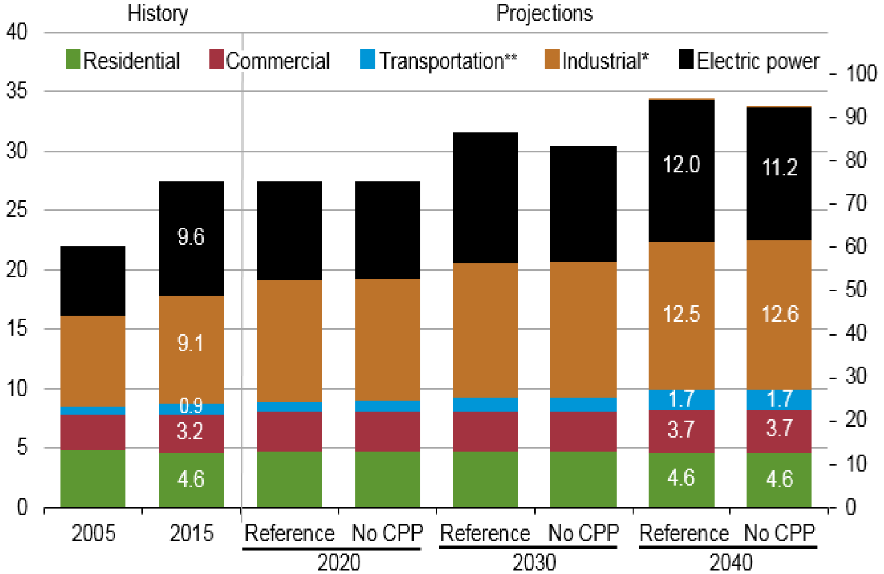
Shale resources remain the dominant source of U.S. natural gas production growth



Source: EIA, Annual Energy Outlook 2016

- The 55% increase in total dry natural gas production from 2015-40 in the Reference Case results from increased development of shale gas and tight oil plays, tight gas, and offshore natural gas resources.
- Production from shale gas and tight oil plays grows by more than 15 trillion cubic feet (Tcf), over 2015-40, reaching 29 Tcf in 2040. The shale gas and tight oil play share of total U.S. dry natural gas production increases from 50% in 2015 to 69% in 2040.
- Tight gas production growth occurs in the sedimentary basins located in the Dakotas/Rocky Mountains and Gulf Coast regions.
- U.S. offshore natural gas production averages around 1.5 Tcf through 2020 before declining due to declines in legacy offshore fields. After 2027, offshore natural gas production again increases as production from new discoveries more than offsets the decline in legacy fields.

Natural gas consumption growth is led by electricity generation and industrial uses; natural gas use rises in all sectors except residential

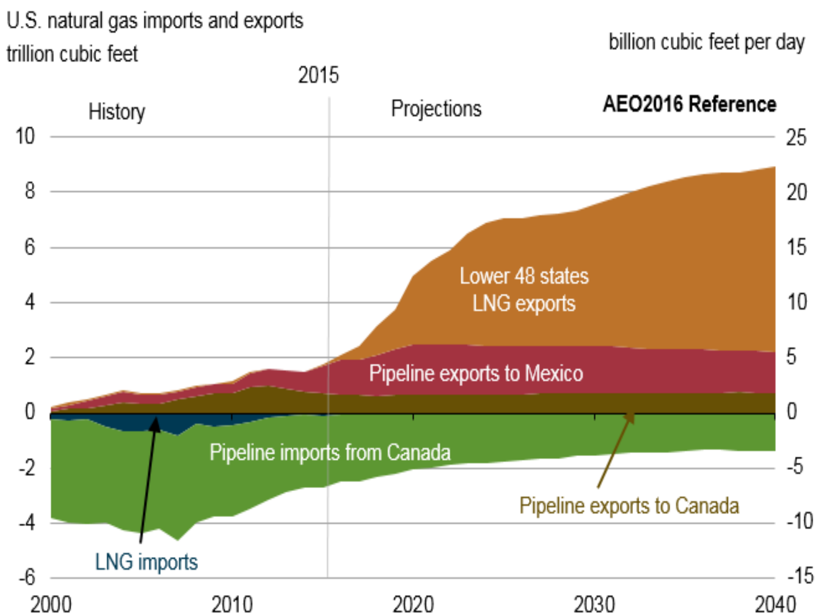


Source: EIA, Annual Energy Outlook 2016

*Includes combined heat-and-power and lease, plant, and export liquefaction fuel
**Includes pipeline fuel

- Natural gas consumption grows with increased supply and competitive prices, with the largest growth seen in the electric power and industrial sectors after 2020, the Clean Power Plan results in increased natural gas consumption for electricity generation.
- In the early years, when prices rise off of their low levels in 2015 and 2016, the growth in consumption slows and reverses for several years, particularly in the electric power sector. After 2016, natural gas-fired generation grows as coal use continues to decline and natural gas prices remain competitive.
- Strong and continued growth in the industrial sector is driven by energy-intensive industries that use natural gas as a feedstock, such as bulk chemicals, lease and plant fuel (which grows with production), and liquefaction fuel used in producing liquefied natural gas for export.
- Although, historically, little natural gas has been used in the transportation sector, the sector uses a small but growing share of natural gas in AEO2016.

The United States remains an importer and exporter of natural gas over the projection period, moving from a net importer to a net exporter in 2018



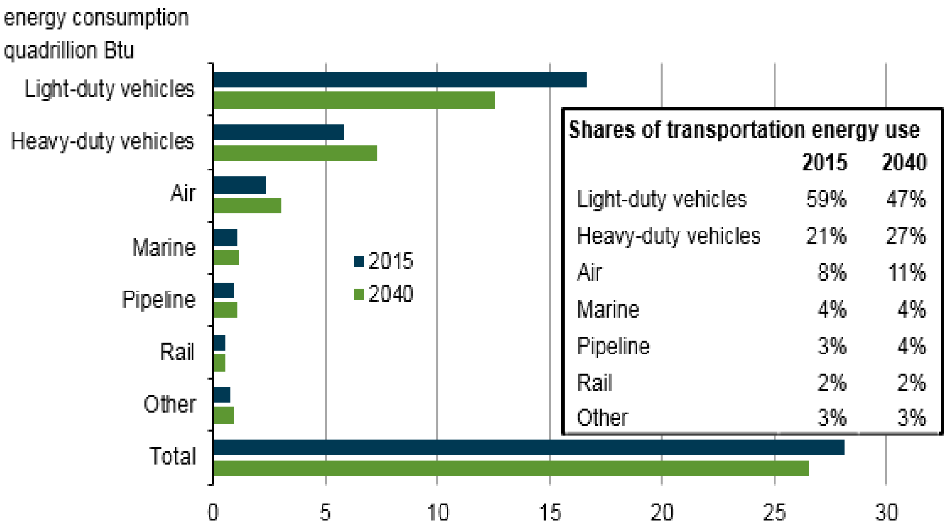
Source: *EIA, Annual Energy Outlook 2016*

- Natural gas imports into the United States fall by 49% from 2015-40 and natural gas exports from the United States, both by pipeline and liquefied natural gas (LNG), grow by over five-fold. The five LNG export projects currently built or under construction in the Mid-Atlantic and the Gulf Coast regions, with capacity to export 2.9 trillion cubic feet (Tcf)/year, largely account for the initial rapid growth in exports; additional facilities will be required in the Reference Case to accommodate LNG exports of 6.7 Tcf in 2040.
- U.S. natural gas exports to Mexico by pipeline will continue to increase in the near term. While Mexico's natural gas production is declining, its natural gas consumption is increasing, particularly in the electric power sector. The growth in near-term consumption will be met by several pipeline projects currently under construction. After 2020, U.S. pipeline exports to Mexico gradually decrease, reflecting the initiation of new oil and natural gas production projects in Mexico and the increased use of renewables for electricity generation.
- U.S. net imports from Canada continue to decline as relatively low prices and a closer proximity to major U.S. markets make natural gas produced in the United States more competitive.

Delivered energy consumption by sector

Light-duty vehicles are the only mode of travel projected to have a decrease in energy consumption share because of improvements in new vehicle fuel economy required under the Corporate Average Fuel Economy standards

Delivered energy consumption for transportation by mode in the Reference case, 2015 and 2040



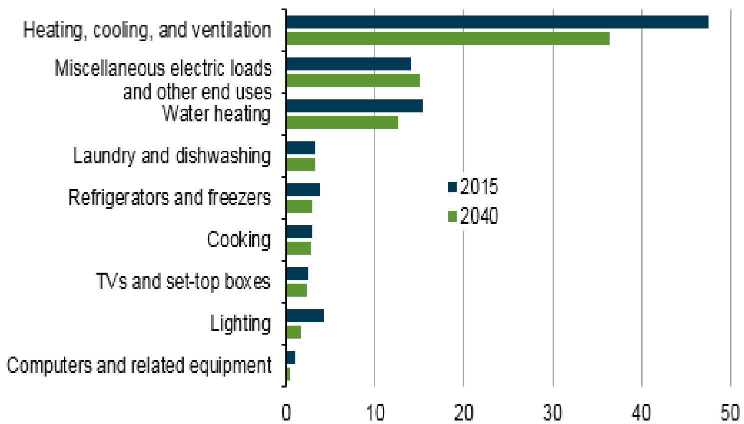
Source: EIA, Annual Energy Outlook 2016

- A decline in light-duty vehicle energy consumption reduces its share overall transportation energy use.
- Heavy-duty vehicle and air represent the fastest growing transportation modes in the projection.
- The full AEO2016 will include a case that incorporates the proposed Phase 2 fuel economy standards for heavy-duty trucks, which can significantly affect projected fuel use.

Energy efficiency policies and standards, and population shifts to warmer climates in the south and west, contribute to declining energy intensity in the residential sector

Residential sector delivered energy intensity for selected end uses in the Reference case, 2015 and 2040

energy intensity
million Btu per household per year



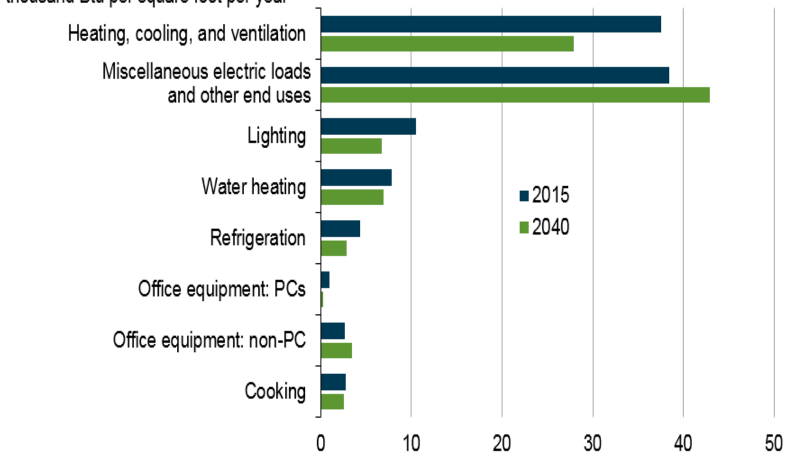
Source: EIA, Annual Energy Outlook 2016

- Annual delivered energy use per household declines by 18% (0.8%/year on average) over 2015-40 in the Reference case.
- Lighting, affected by the phase-in of light bulb efficiency standards from the Energy Independence and Security Act of 2007 and efficiency subsidies provided as part of implementation of the Clean Power Plan, plays a key role in reducing household energy intensity.
- Continued growth of renewable capacity in homes, such as rooftop solar photovoltaic panels, also reduces delivered energy intensity, since distributed generation for direct use reduces the need for delivered energy (purchased from an energy provider).
- Per household use of miscellaneous electric loads and other end uses increases, with increasing market penetration of smaller electric devices.

Despite 1.1% average annual growth in commercial floorspace from 2015 to 2040, commercial delivered energy intensity (energy use per square foot) decreases 0.5%/year in the Reference case

Commercial sector delivered energy intensity for selected end uses in the Reference case, 2015 and 2040

energy intensity
thousand Btu per square foot per year

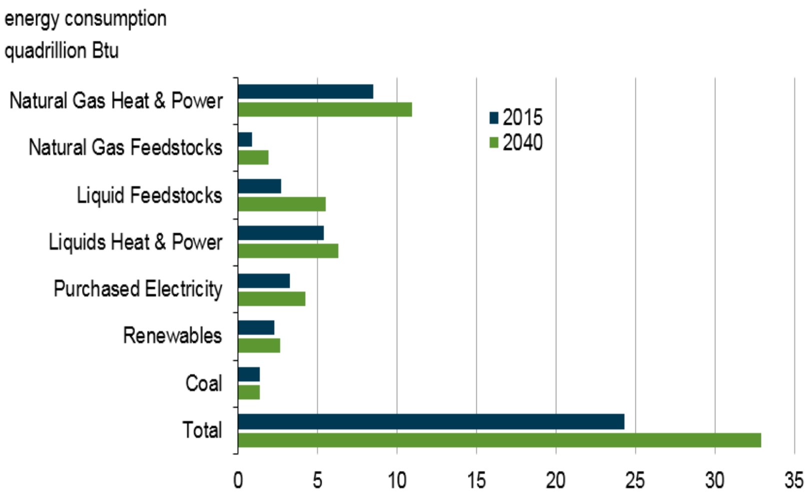


Source: EIA, Annual Energy Outlook 2016

- Almost every major use of energy in commercial building consumption, such as space heating and cooling, water heating, lighting, and refrigeration, is covered by federal energy efficiency standards.
- As a result of efficiency standards, technology advances, and implementation of the Clean Power Plan, energy intensity for commercial lighting and refrigeration decreases at annual average rates of 1.8%/year and 1.7%/year through 2040, respectively, while space heating and cooling intensity declines 1.2%/year
- Energy intensity of miscellaneous electric loads grows 11.5% with the proliferation of medical imaging equipment, video displays, and other electric devices.
- Growth in commercial non-personal computer (PC) office equipment is largely driven by the increasing use of data centers for web- and network-based services and connectivity. PC office equipment decreases as users shift from desktop computers to more efficient laptops and mobile computing devices.

Total delivered industrial energy consumption grows by 1.2%/year from 2015-40, while the value of industrial shipments grows 1.9%/year

Delivered energy consumption for industrial sector by fuel in the Reference case, 2015 and 2040



Source: EIA, Annual Energy Outlook 2016

- The rate of growth in industrial energy use is higher in the 2015-25 period, averaging 1.7%/year, than in the 2025-40 period, averaging 0.7%/year, because shipments, especially from energy-intensive sectors, grow at a faster pace in the earlier period.
- Natural gas consumption for heat and power grows strongly, largely as a result of strong industrial shipments growth in bulk chemicals. By 2040, bulk chemicals energy use will constitute almost one third of total industrial energy consumption.
- Natural gas feedstocks in the bulk chemicals industry increase 3.5%/year between 2015 and 2040 as a result of growing agricultural chemicals shipments.
- Purchased electricity consumption in industry increases at an annual average rate of 1.1% over 2015-40 as efficiency improvements partially offset shipments growth.
- Slow growth in industrial renewables use reflects slow shipments growth in the paper industry, the largest user.

For more information

U.S. Energy Information Administration home page | www.eia.gov

Annual Energy Outlook | www.eia.gov/forecasts/aeo

Short-Term Energy Outlook | www.eia.gov/forecasts/steo

International Energy Outlook | www.eia.gov/forecasts/ieo

Today In Energy | www.eia.gov/todayinenergy

Monthly Energy Review | www.eia.gov/totalenergy/data/monthly

State Energy Portal | www.eia.gov/state

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PJM Clean Power Plan Modeling Preliminary Phase 1 Long-Term Economic Compliance Analysis Results

May 6, 2016

PJM's Clean Power Plan Modeling

What it is

Robust modeling representation of potential system futures driven by policy, regulatory and market drivers

What isn't it

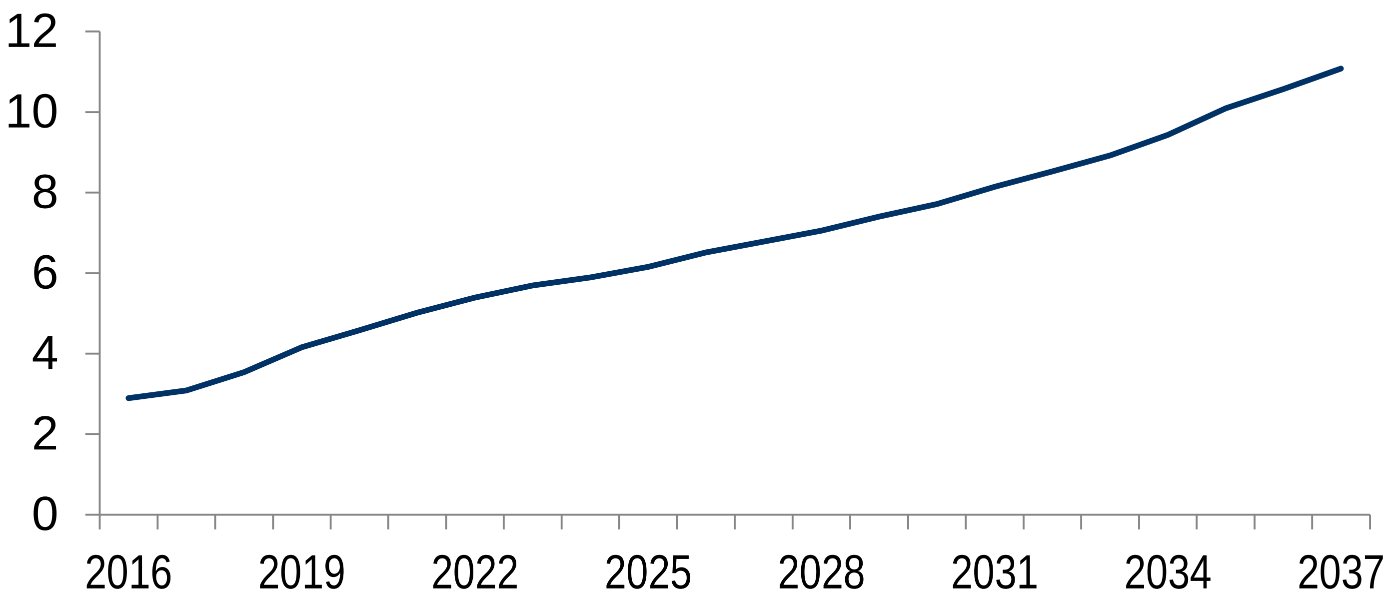
- An economic forecast of expected future outcomes
- A representation of all the considerations resource owners may make in investing in new assets or retiring existing assets

Key Assumptions

Reference Model	Represents the extension of Production and Investment Tax Credit, but no Renewable Portfolio Standard, and a **future without the Clean Power Plan**
Sensitivities	
Reduce Energy Efficiency Emission Rate Credits by 50%	Applied to Trade-Ready Rate Scenario

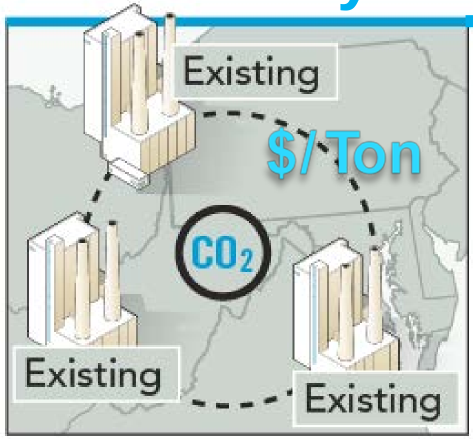
Key Inputs	Description
Inflation	2.25%
Effective Tax Rate	40%
Weighted Average Cost of Capital	8%
Study Horizon	2018 to 2037

Henry Hub Natural Gas Price Forecast ($/mmbtu)



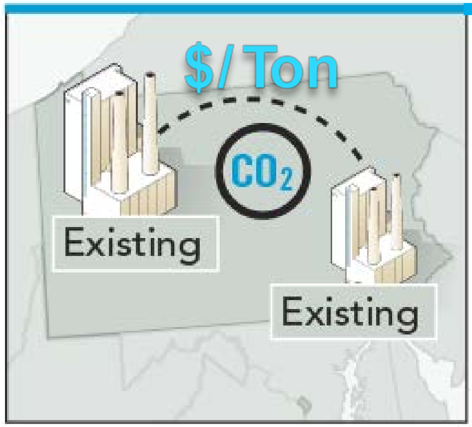
Mass-Based Compliance Pathway Scenarios

Trade-Ready



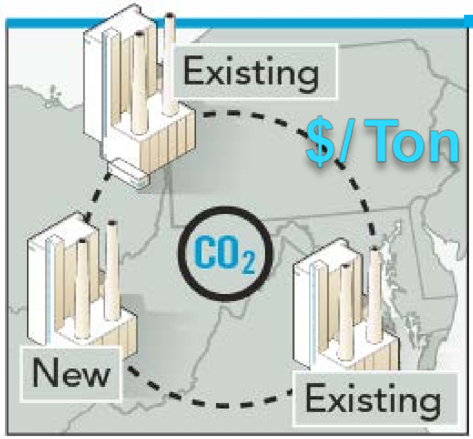
Single CO_2 limit applied to the PJM region for 111(d) existing resources

State Mass



Each state applies a CO_2 limit covering all 111(d) existing resources

New Source Complement (NSC)



Single CO_2 limit applied to the PJM region for 111(d) existing and 111(b) new sources

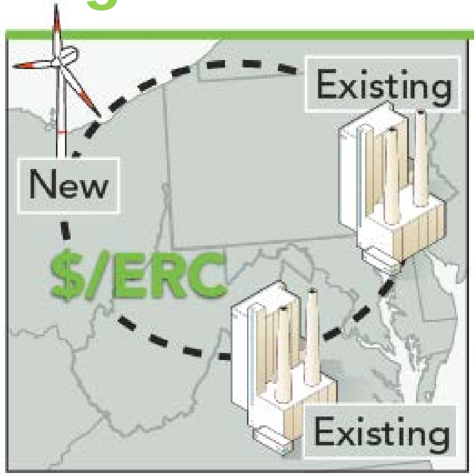
State Mass New Source Complement

Each state applies a CO_2 limit covering all 111(d) existing resources and 111(b) new sources

[1] Proposed Federal Plan for the Clean Power Plan (PDF) - http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22848.pdf

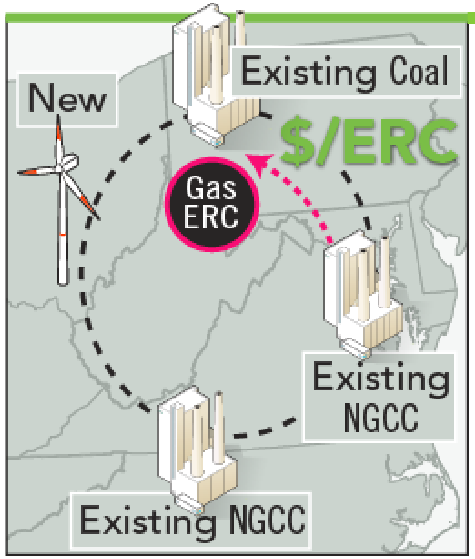
Rate-Based Compliance Pathway Scenarios

Regional Blended Rate



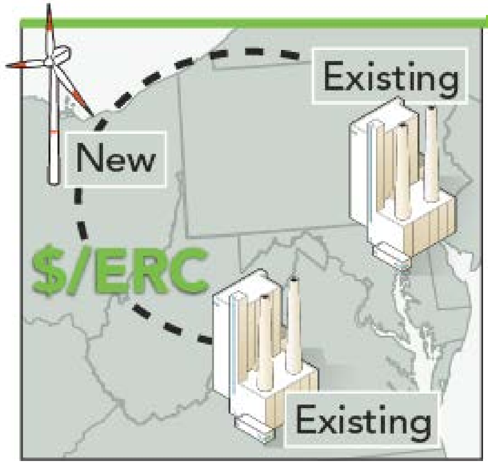
Emissions performance measured against a weighted average of PJM states' CO_2 emissions rates

Trade-Ready Rate



Emissions performance measured against the sub-category CO_2 emission rate targets for combined cycle and steam turbine resources

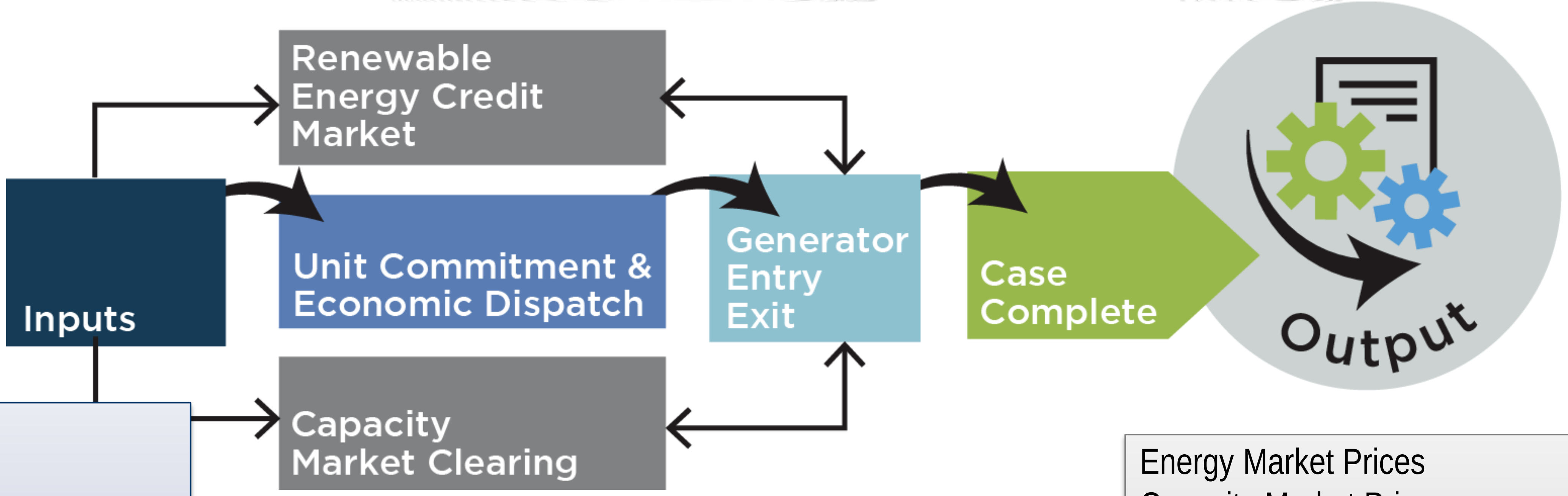
State Blended Rate



Emissions performance measured against the state CO_2 emissions rate target

[1] Proposed Federal Plan for the Clean Power Plan (PDF) - http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22848.pdf

Compliance Analytics Diagram



Load Forecast
Fuel Prices
Unit Operational Constraints
Emissions Constraints
Transmission Constraints
Fuel Supply Limitations
Capacity Market Bids
Renewable Portfolio Standards
Demand Response

Energy Market Prices
Capacity Market Prices
Emissions Market Prices
Resource Adequacy Evaluation
Ancillary Service Market Prices
Renewable Energy Credit Prices
Transmission Constrained Areas
Fuel Constrained Areas
New Build Capital Costs

Executive Summary

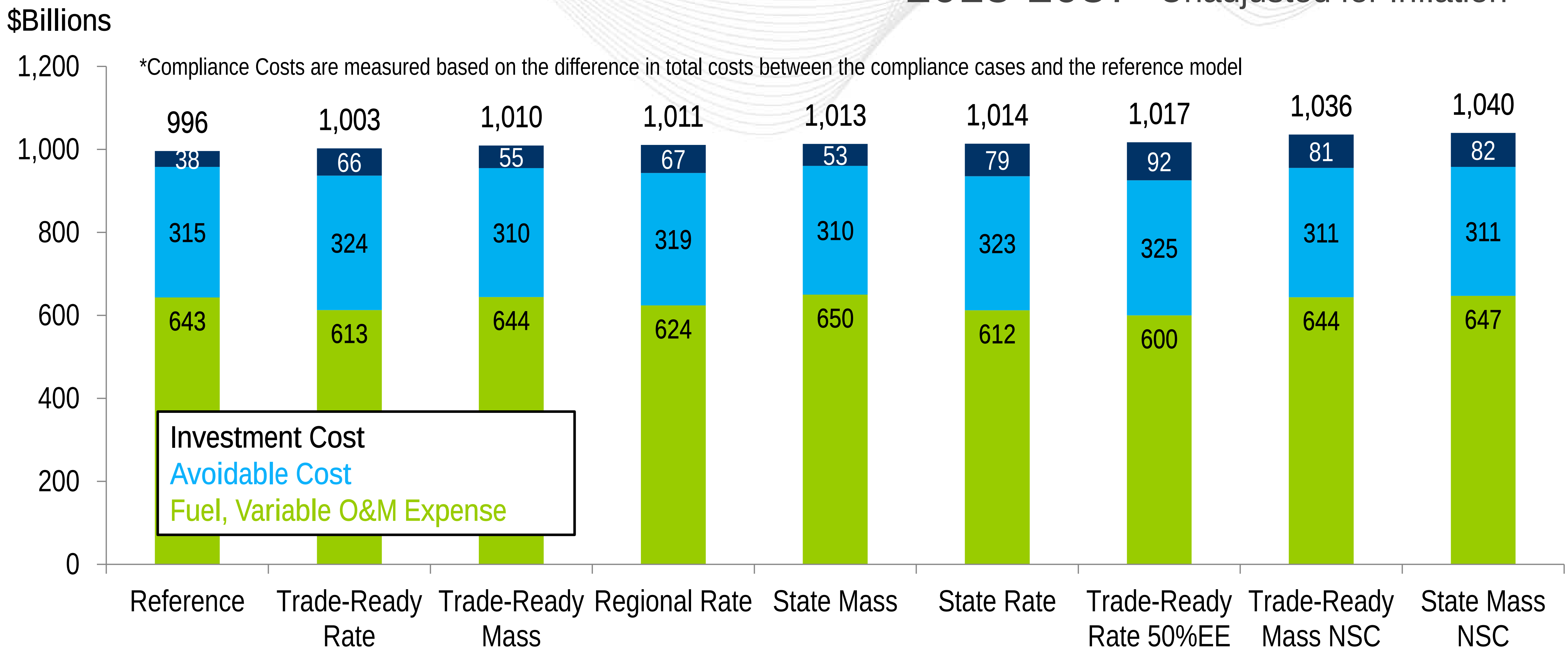
- Trade-ready/regional compliance leads to lower compliance costs.
- Mass-based compliance provides more certainty in emissions levels than rate-based.
- Rate-based compliance can lead to fewer retirements than mass-based compliance but is sensitive to the amount of credits created for zero-emitting resources
- Rate-based compliance reduces wholesale energy market prices relative to mass-based compliance which can negatively impact zero-emitting resources.

Because of PJM's regional economic operations...

- Comparable resources in neighboring states can be dispatched independent of the chosen compliance pathway.
- Interstate or intrastate trading of emissions allowances and credits affects wholesale prices only when they change the marginal resource in energy or capacity markets.

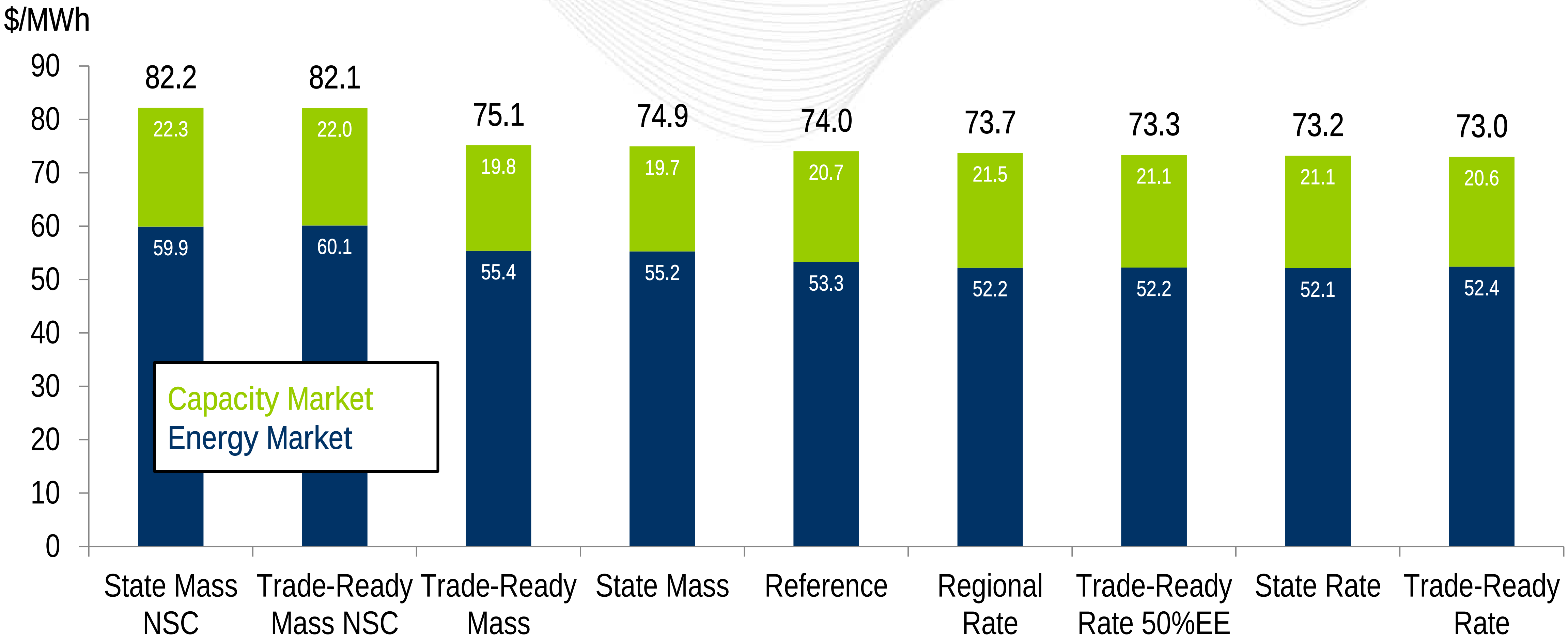
Market and Investment Costs

Generator Production, Avoidable and Investment Costs 2018-2037 *Unadjusted for Inflation

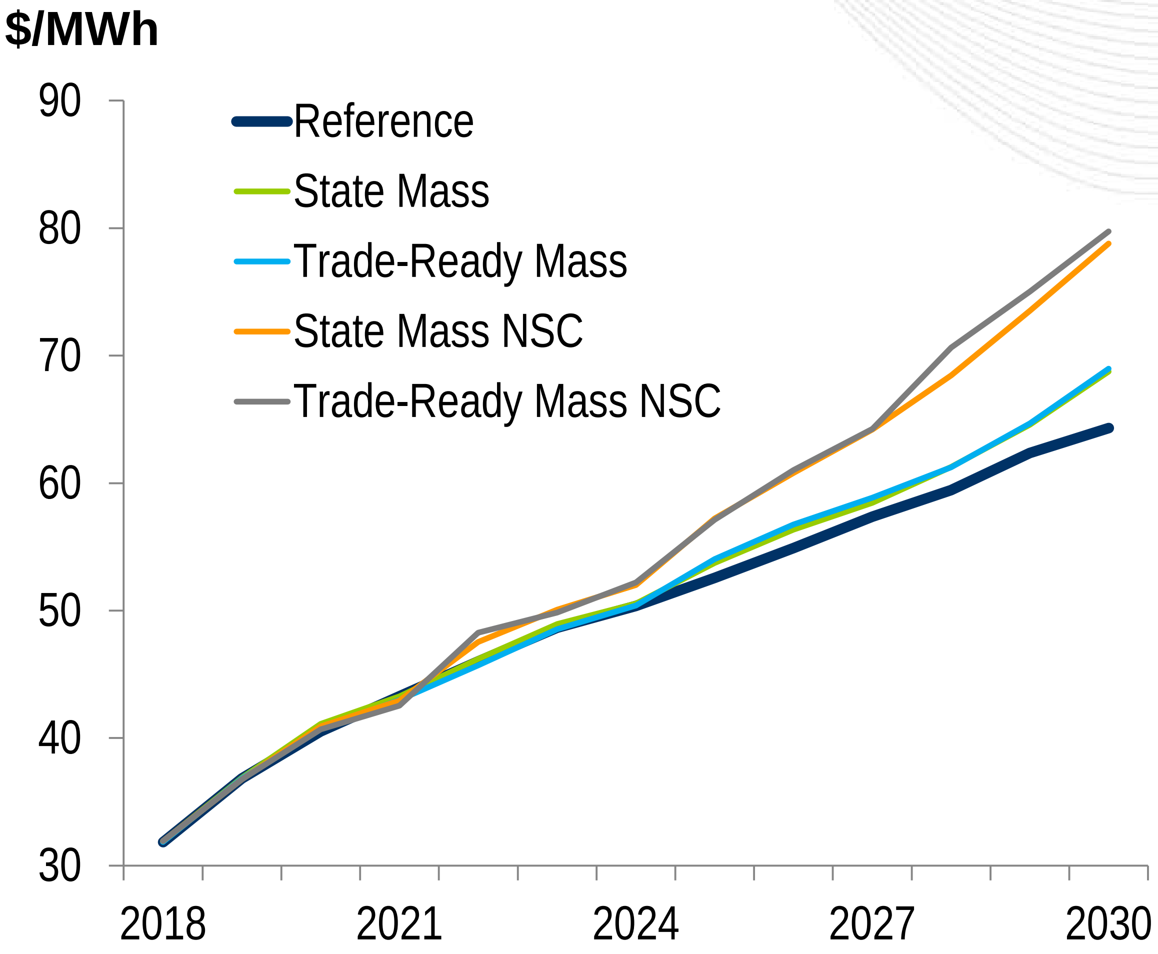


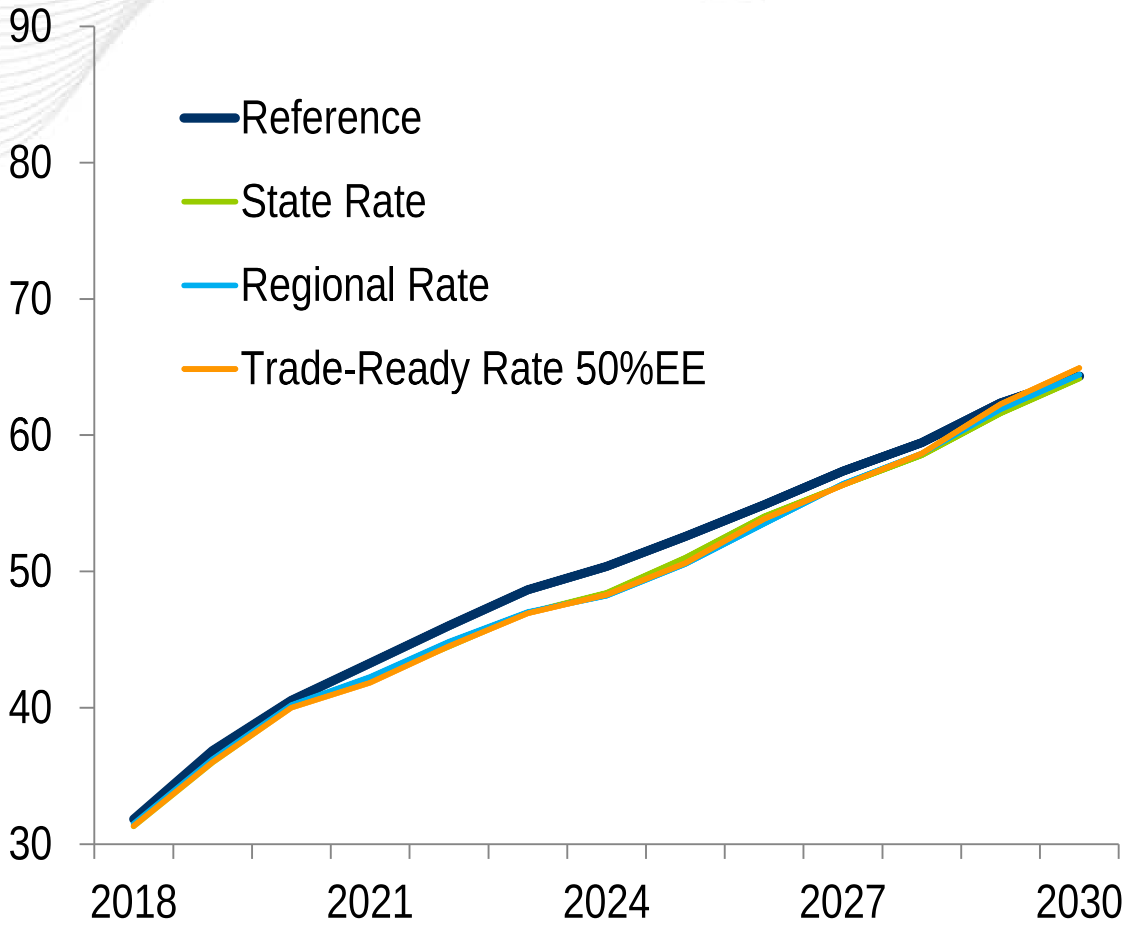
Avoidable cost shown does not capture non-dispatchable existing resources or small (< 25 MW) dis-patchable resources.

Levelized Energy and Capacity Market Costs Study Horizon: 2018-2037



PJM Load-Weighted Energy Market Price

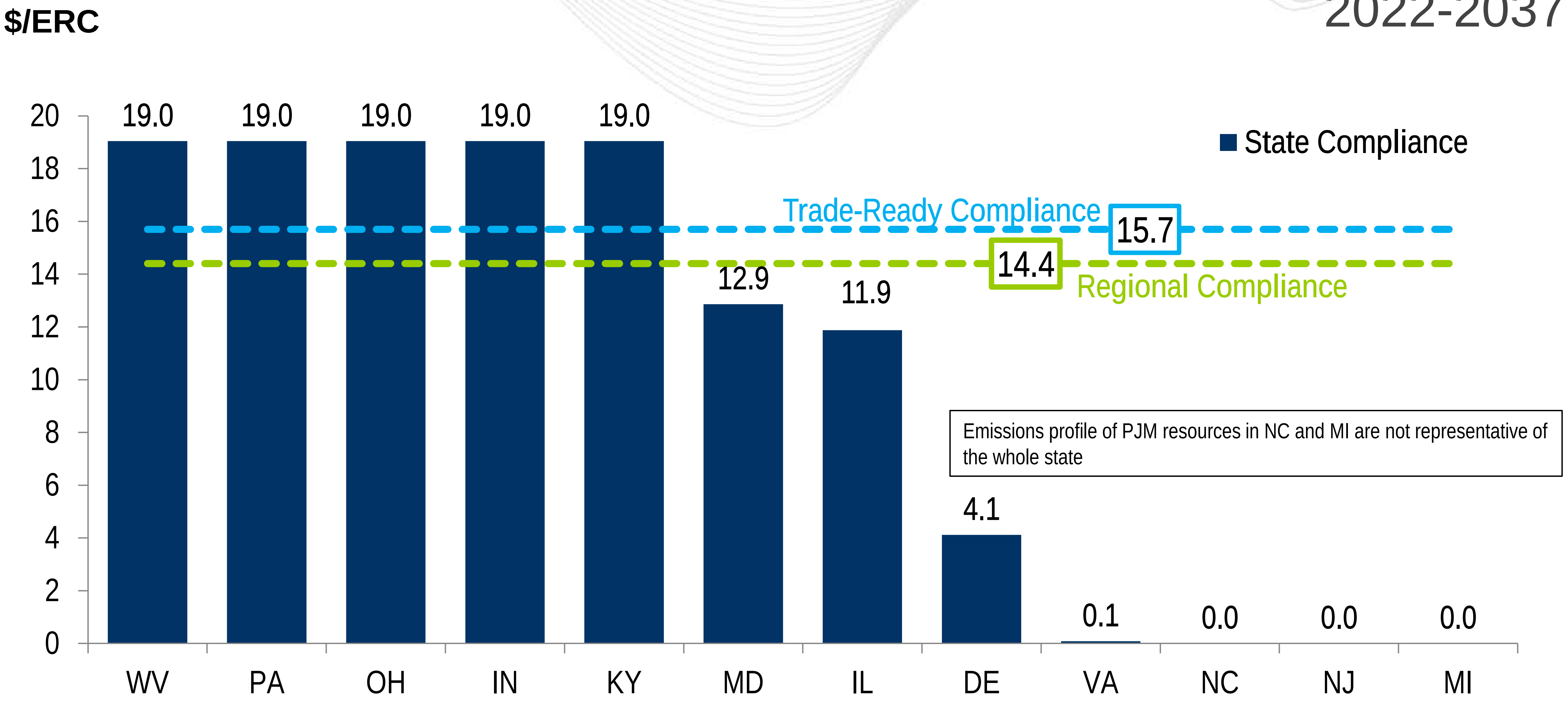




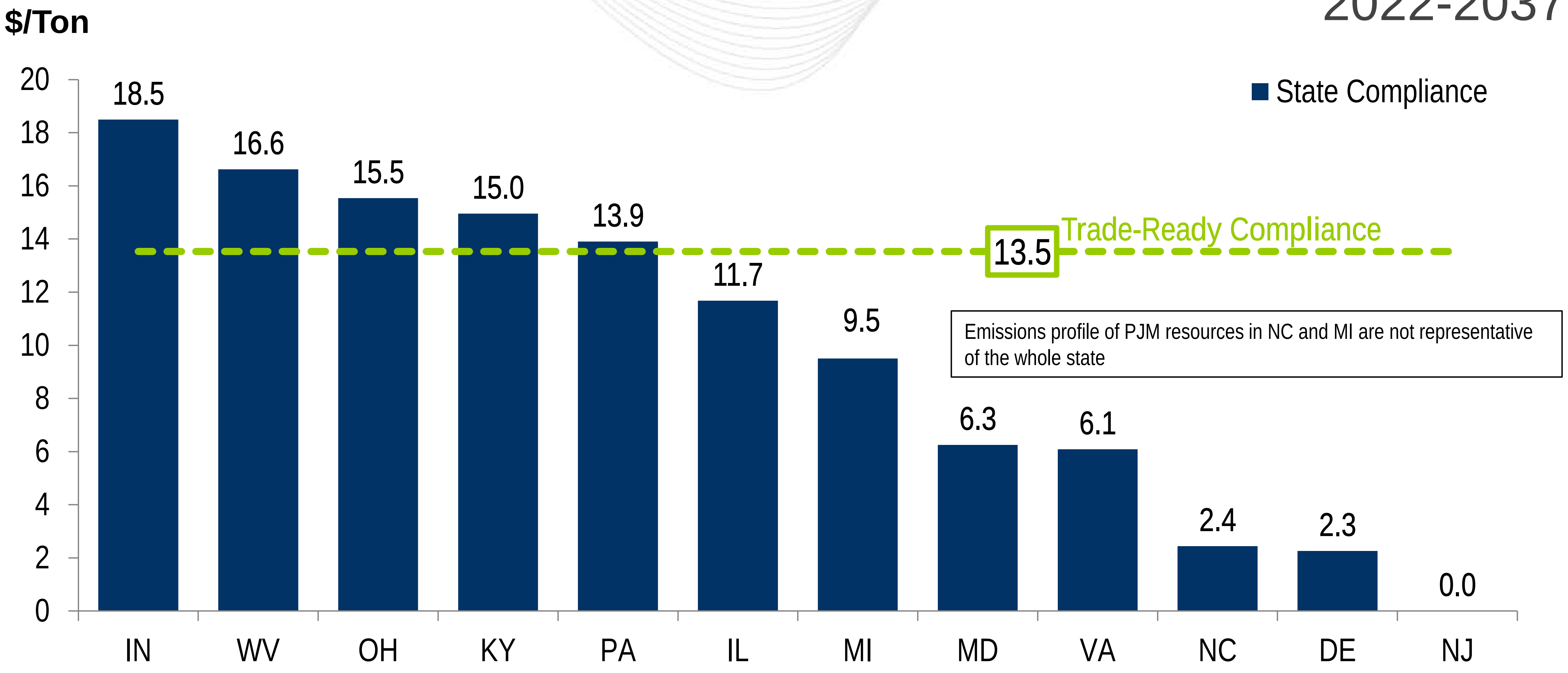
CO_2 Emissions Markets

Ex. TFC - 49

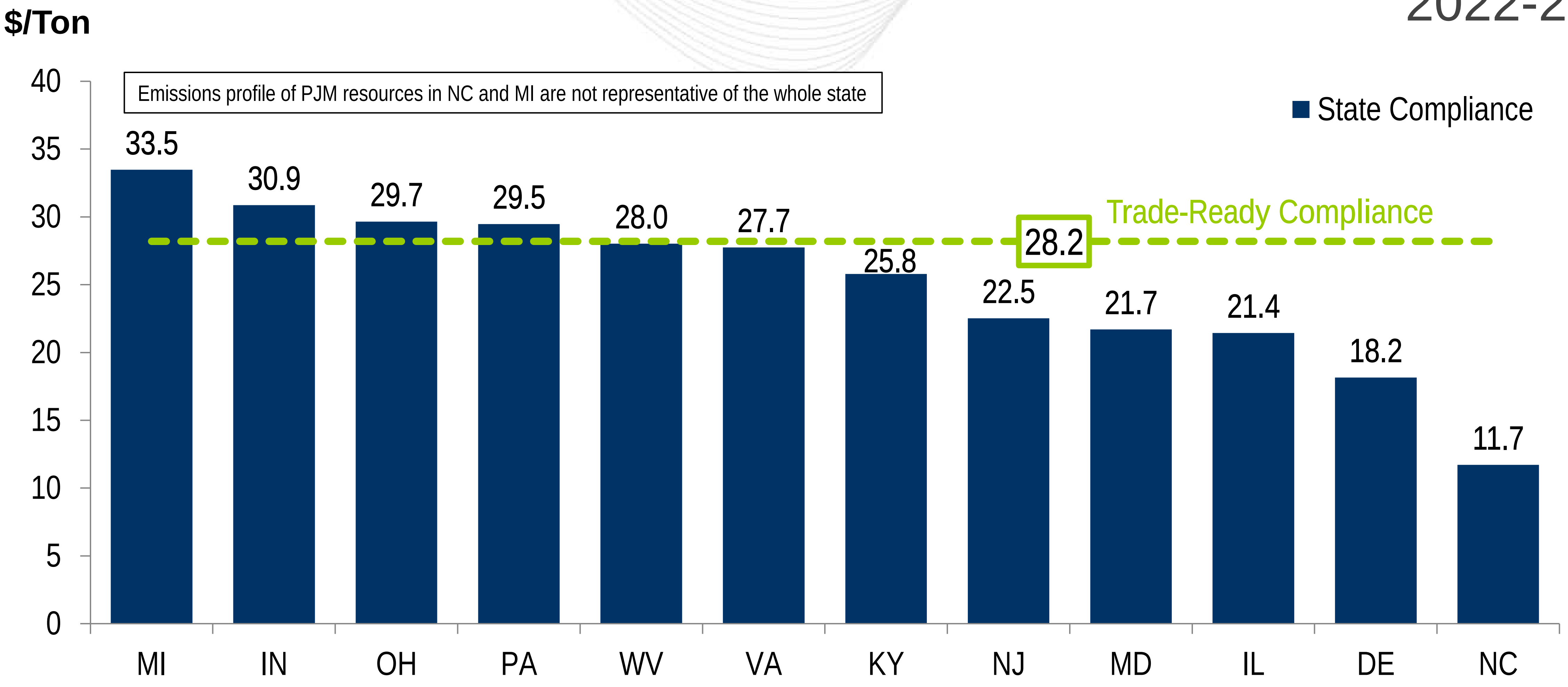
Rate-Based Compliance Pathways
Average Emission Rate Credit Prices for PJM resources 2022-2037



Mass-Based Existing Source Compliance Pathways Average Allowance Prices for PJM resources 2022-2037

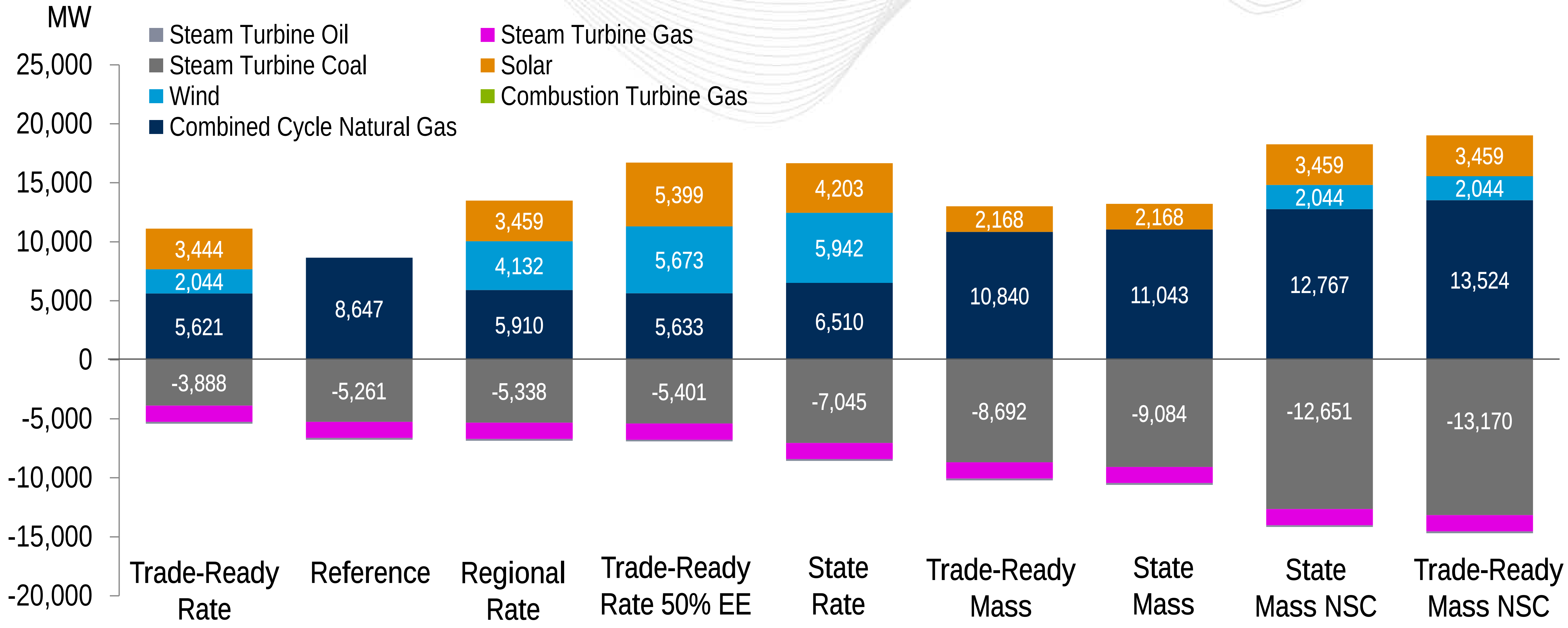


Mass-Based Existing and New Source Compliance Pathways Average Allowance Prices for PJM resources 2022-2037



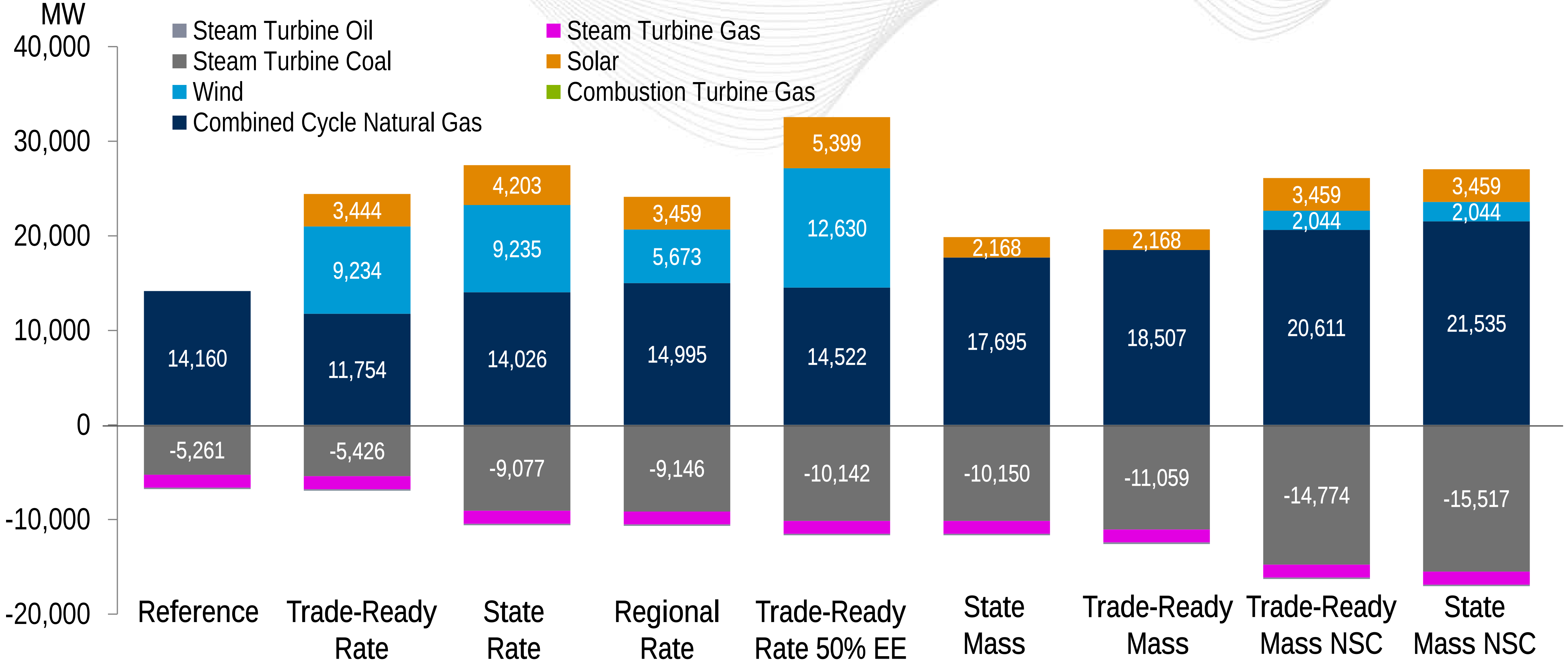
Generating Unit Entry and Exit

Economic Generation Entry/Exit by 2025



Note: The model represents levelized going forward costs, but does not attempt to capture additional capital investments for coal or nuclear units which can affect going-forward decisions at various times.

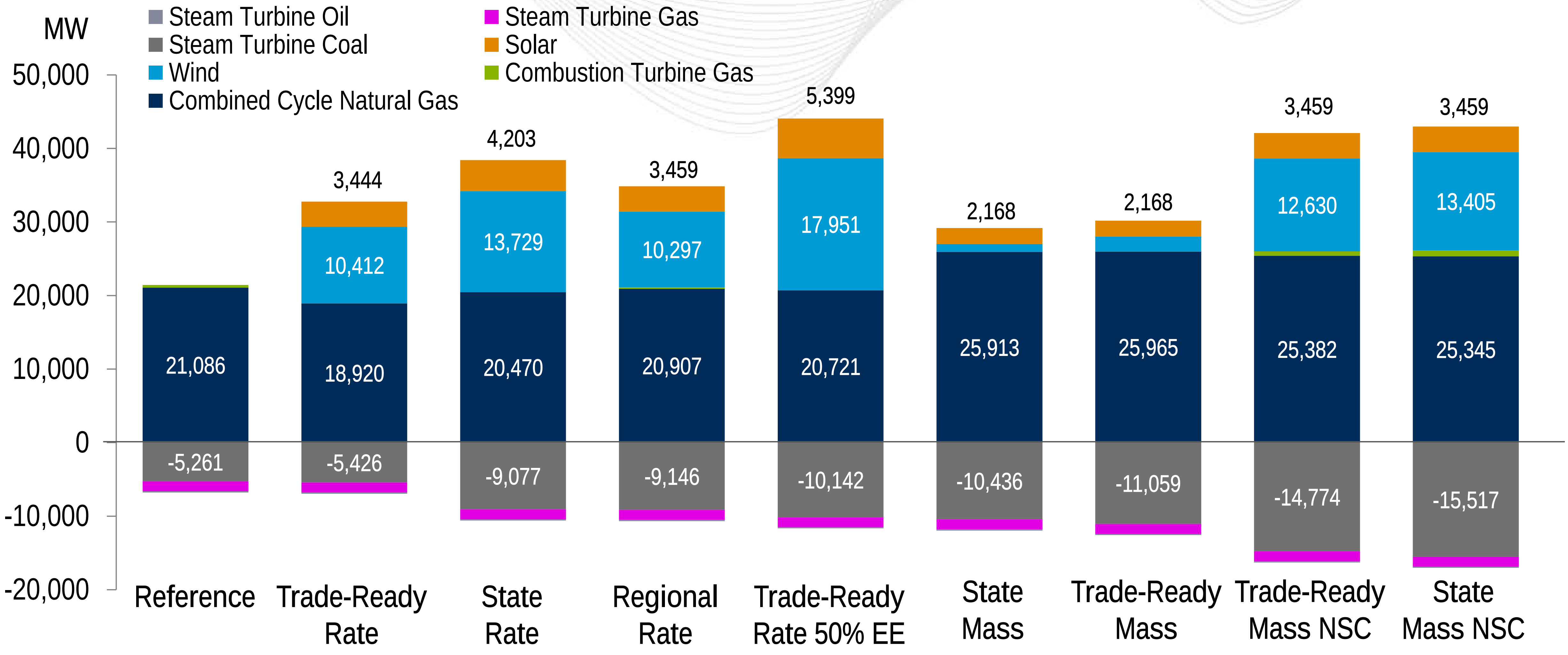
Economic Generation Entry/Exit by 2030



Note: The model represents levelized going forward costs, but does not attempt to capture additional life extension costs for coal or nuclear units.

Ex. TFC - 49

Economic Generation Entry/Exit 2018-2037

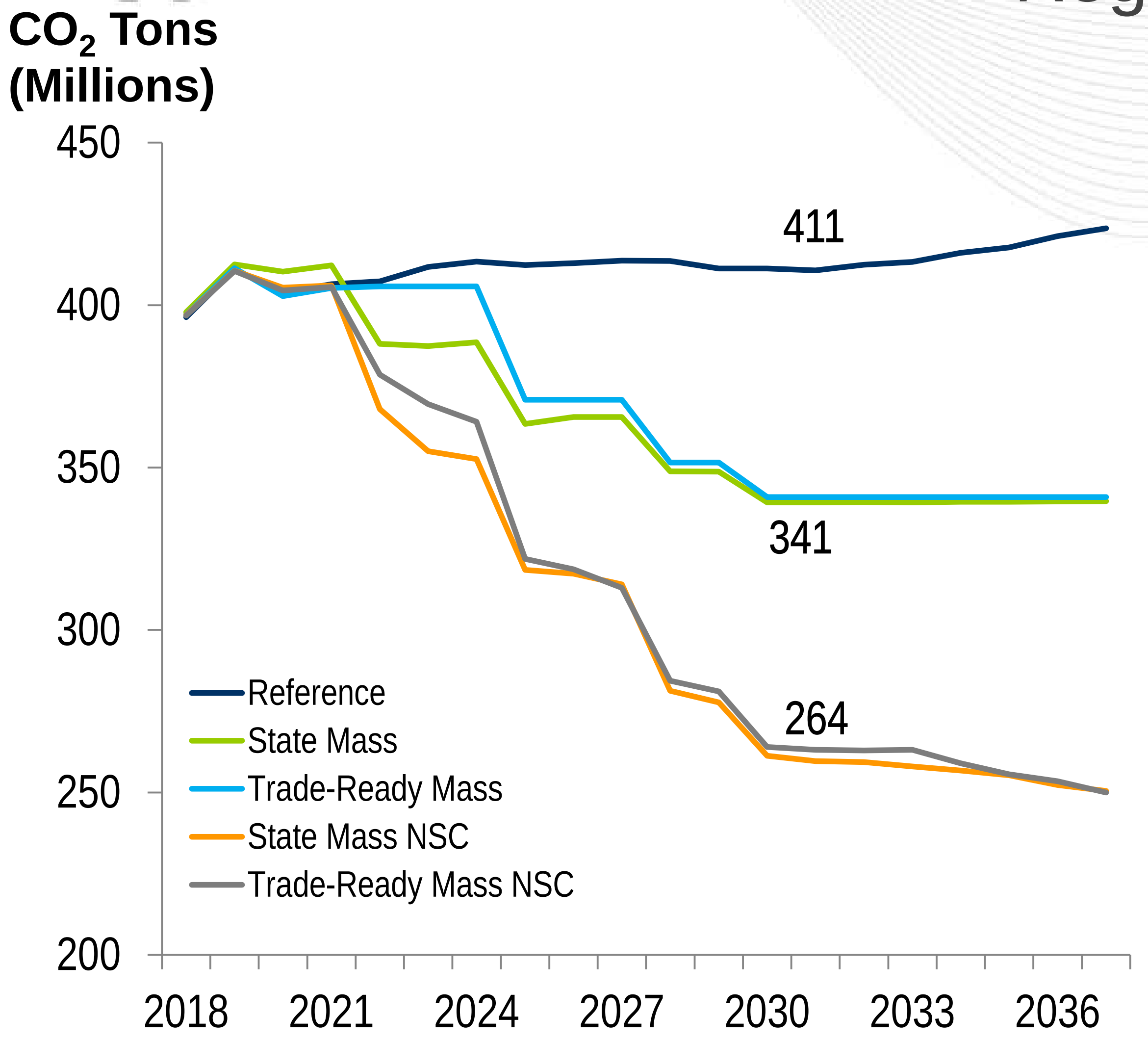


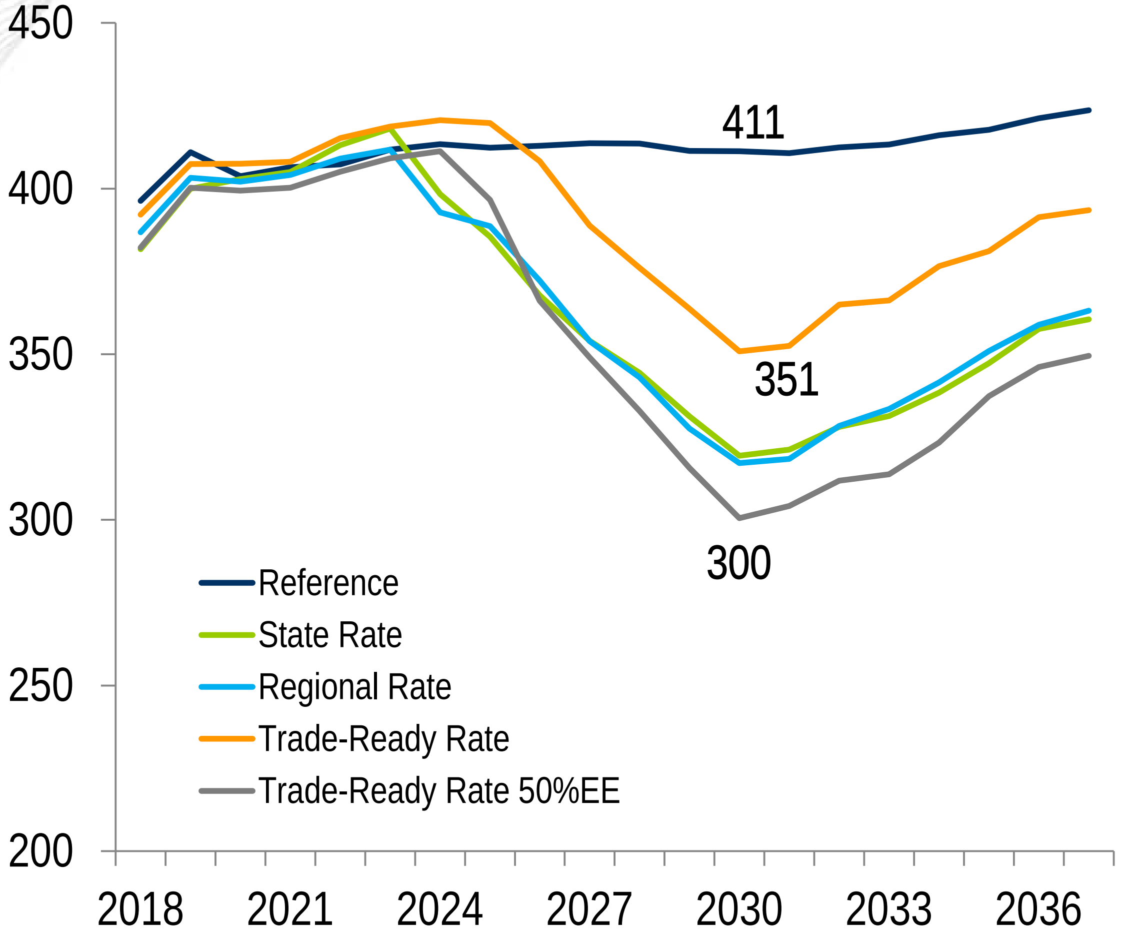
Note: The model represents levelized going forward costs, but does not attempt to capture additional capital investments for coal or nuclear units which can affect going-forward decisions at various times.

PJM Region CO_2 Emissions

Ex. TFC - 49

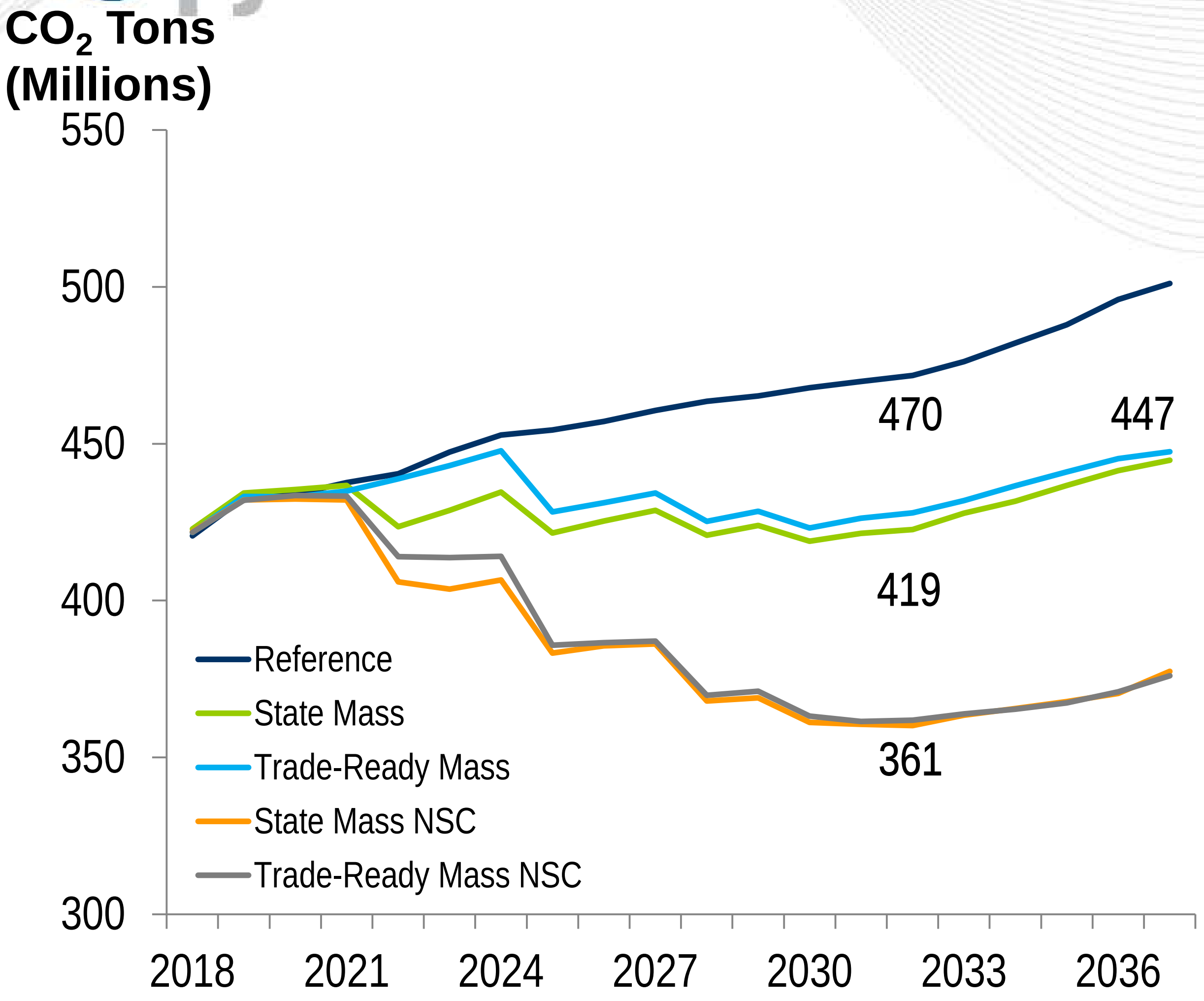
CO_2 Emissions from PJM sources Regulated under the Clean Power Plan

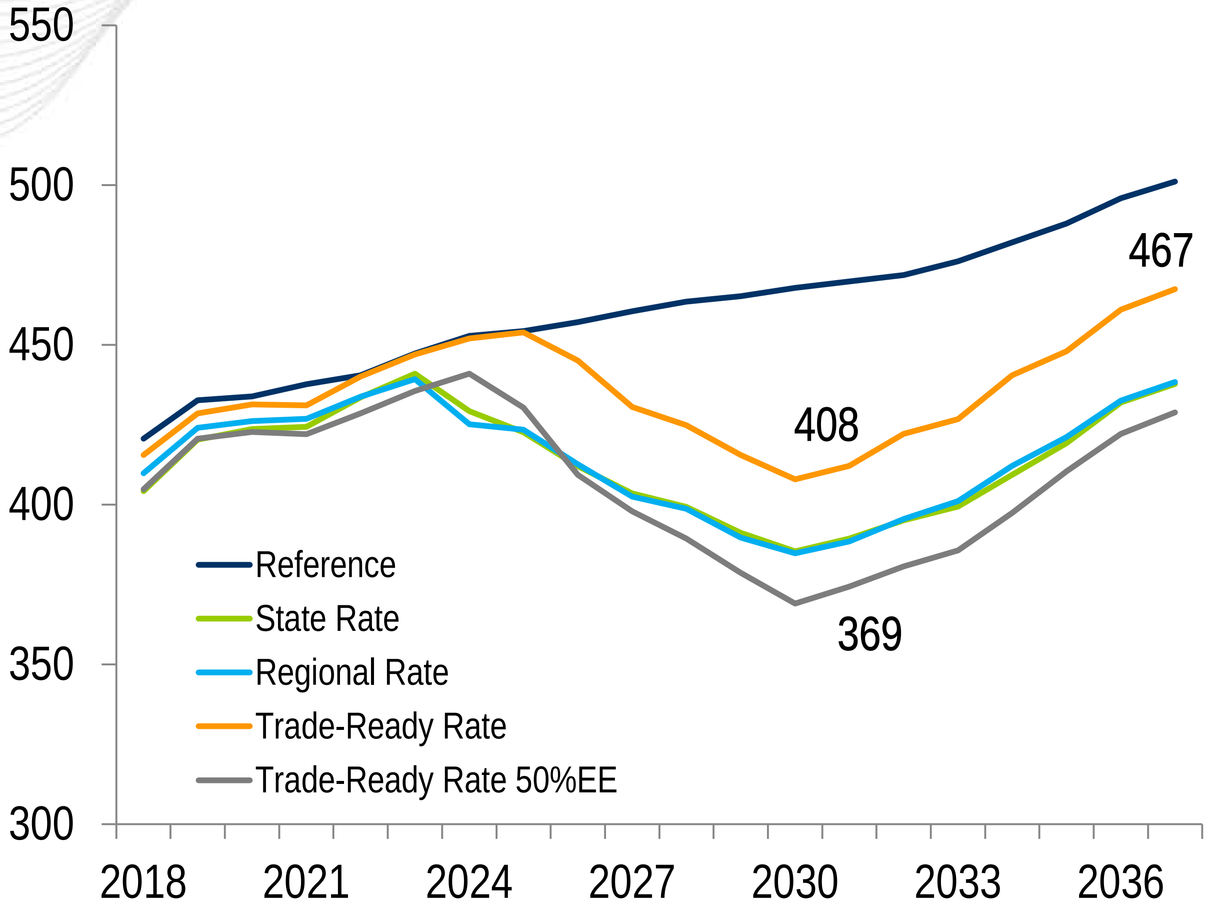




Ex. TFC - 49

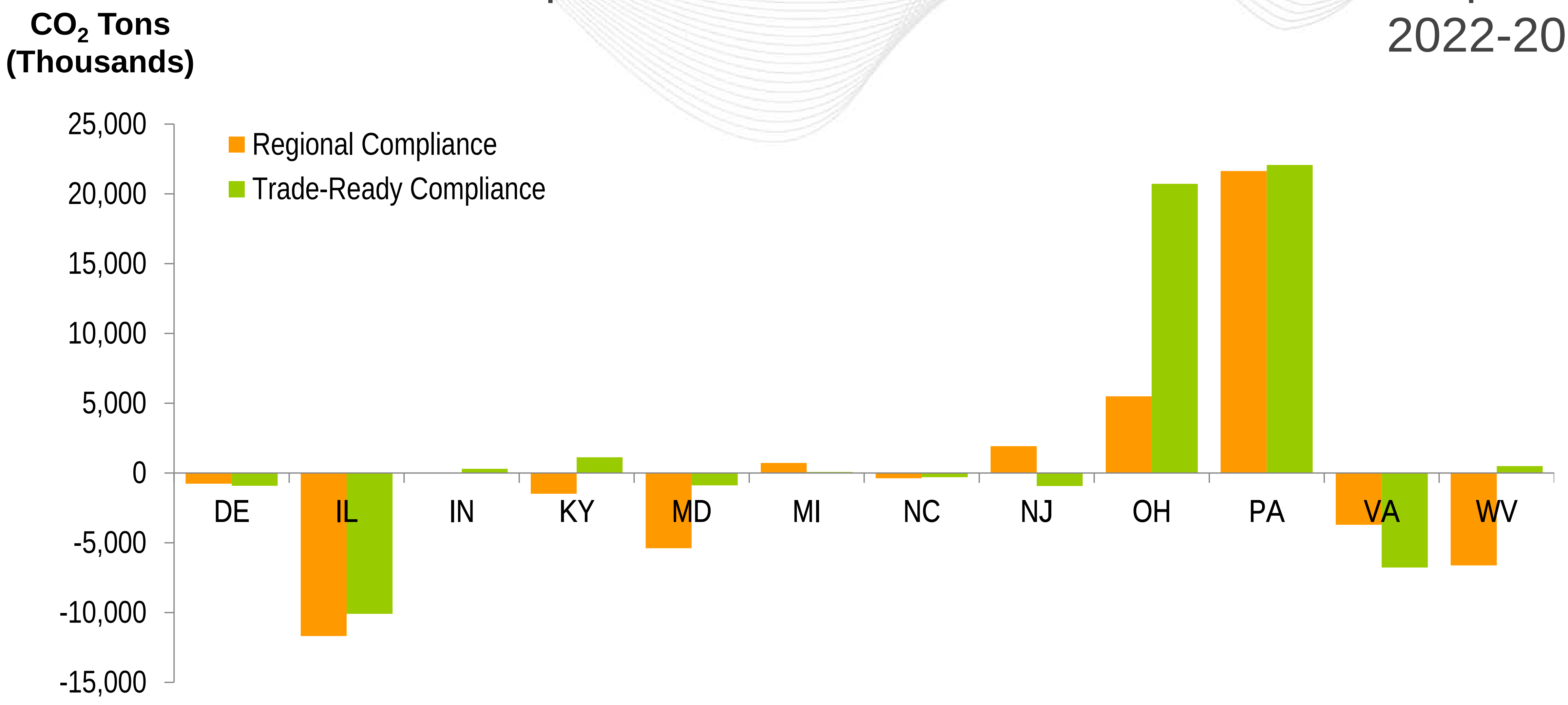
CO_2 Emissions from All PJM sources under the Clean Power Plan





Ex. TFC - 49

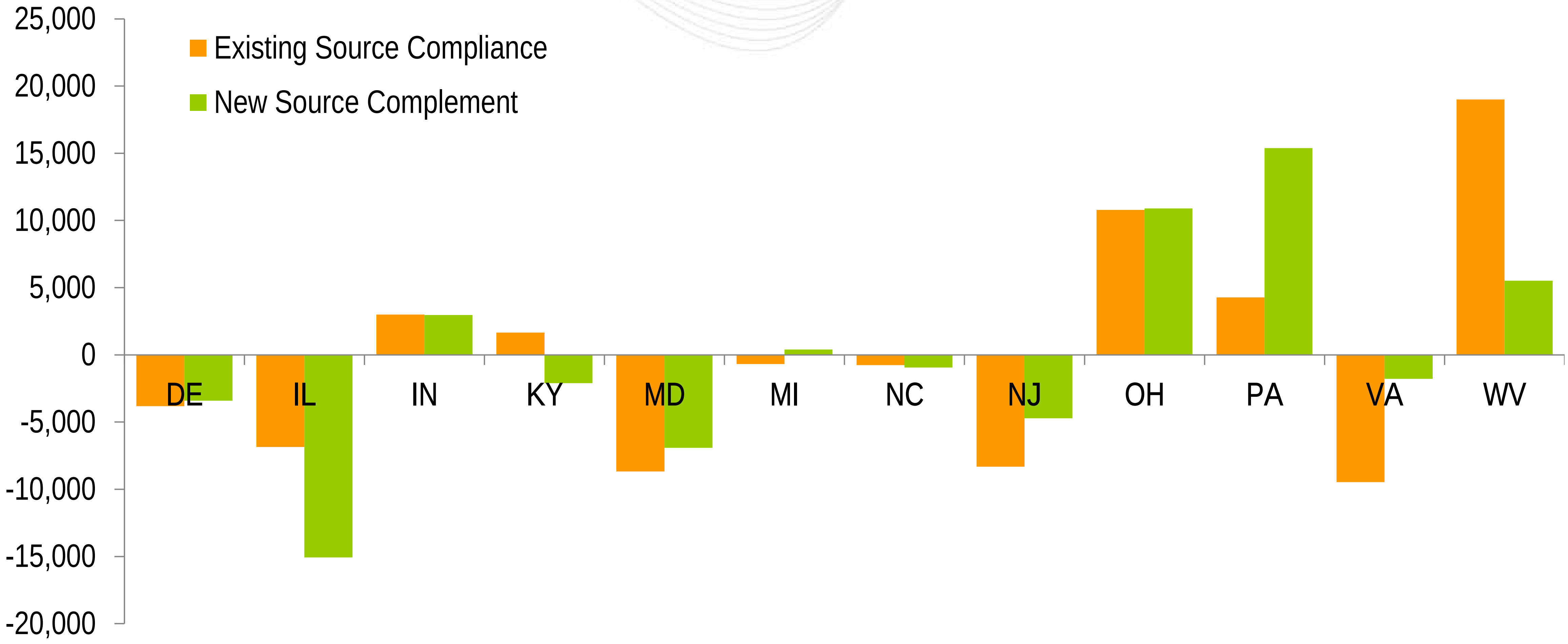
Average Differences in CO_2 Emissions for Multi-state Compliance versus Intrastate Rate-Based Compliance 2022-2037



Ex. TFC - 49

Average Annual CO_2 Emissions above the State Cap under Trade-Ready Mass Compliance 2022-2037

CO_2 Tons (Thousands)



Key Observations

Due to Trade-Ready/Regional Compliance...

- Overall compliance costs is lower
- Emissions reductions are able to come from the least efficient (fuel and O&M cost) and/or highest emitting resources in PJM.
- Distribution of generator retirements across the footprint changes but not necessarily the level of retirements.
- Coal-dominant states can lower their costs of buying allowances and preserve useful life of assets

Due to regional economic dispatch…

- PJM can dispatch comparable resources in neighboring states independent of the compliance pathway selected by PJM states.
- Interstate or intrastate trading of emissions allowances affects wholesale prices only when they change the marginal resource in energy or capacity markets.

Provided distributed resources and energy efficiency embedded in the load forecast show up and are accounted for through state measurement and verification programs…

- Participants within PJM are able to avoid additional investments in new resources to generate emission rate credits and/or reduce emissions.
- Emissions can rebound under rate-based compliance provided these resources show up and are accounted for through state measurement and verification programs.

Due to regulating new 111(b) resources under the new source complement…

- CO_2 emissions are reduced more than any other compliance pathway.
- Wholesale electric costs increase relative to other compliance methods.
- Emissions compliance costs increase, which drives more retirements but also new entry.

Due to the Investment and Production Tax Credits…

- Renewables can be developed economically much earlier in the study horizon.
- Rate-based compliance appears cheaper than it otherwise would and emissions reductions can be delayed.

Due to a direct payment through emissions rate credit value under rate-based compliance…

- Renewables become a more attractive investment than natural gas combined cycles for compliance.
- Less natural gas combined cycles enter the market, which reduces the level of competition between coal and gas resources.

Due to the capacity market revenues…

- Resources are able to enter the market economically to maintain resource adequacy throughout the study horizon.

Due to the ability of renewable resources located in state A to sell emissions rate credits to a resource in state B…

- Resources in rate-based states with limited renewable potential can comply with similar costs as resources in states with greater local renewable potential.
- States with similar fuel mix and demand for emission rate credits face similar compliance cost.

Due to the sub-category rate target for coal resources being higher than the blended rate targets…

- There is less demand for emission rate credits during the early part of the compliance period.
- Emissions rebound effects are much more significant when the amount of energy efficiency and renewable resources increase.
- There are fewer retirements under trade-ready rate compliance than other compliance pathways.

Next Steps

- June 2016 – Complete transmission congestion analysis and Compliance Pathways Economic Assessment Report
- Q3/Q4
  - Perform economic and reliability sensitivities
  - Perform coordinated analysis with MISO

Appendix

Definitions and Acronyms

- All sources – All CO_2 emitting sources reporting to EPA's continuous emissions monitoring system
- Emission Rate Credit (ERC) – mechanism for trading in rate-based market
- Emissions allowance – mechanism for trading in mass-based market
- 111(d) or Existing sources – Steam turbine coal/oil/gas, combined cycle gas built or under-construction by 2012
- New Source Complement (NSC) – Existing sources and new sources covered under the new source performance standard (111b) rules

Clean Power Plan Analysis
2014 Versus 2016 Analysis

	2014 Analysis	2016 Analysis
Simulation Tool	ABB Promod IV	Plexos by Energy Exemplar
Energy Market	Chronological simulation of discrete years (SCED)	Chronological and load duration curve based simulation
Entry/Exit	None (Unit at-risk analysis performed in post-processing)	20-year optimized economic entry/exit based on simulated energy and capacity market revenues
Capacity Market	None	20-year BRA clearing for RTO within simulation
Reserves	RTO operating reserves	RTO operating reserves
Renewable Portfolio Standard (RPS)	Scenario based (RPS targets achieved)	Market optimization based on Renewable Energy Credit clearing prices (REC and SREC), energy and capacity market results
GHG Emissions	Dispatch to price (Manually iterate on emissions price)	Single-Step optimization for annual or multi-year constraints
SO_2 and NO_x	ABB forecasts	ABB forecasts
Combined Cycle and Combustion turbine siting	Queue units with an Interconnection Service (ISA) or Facilities Study Agreement (FSA)	Units with permits added automatically. Remaining queue projects enter when economic (FSA/ISA preference)

Evolved analytical approach to evaluate compliance impacts over a wider range of state and multi-state compliance scenarios

Modeling Assumptions

	Combined Cycle	Combustion Turbine	Nuclear	Coal	Solar	Wind
Overnight Capital Costs	Brattle 2014 PJM Costs of New Entry study	Brattle 2014 PJM Costs of New Entry study	EPA v5.13	N/A	NREL ATB 2015 - 2018 Technology year	NREL ATB 2015 - 2018 Technology year
Technical Life	30	30	40	N/A	20	20
Depreciation	MACRS 20-year	MACRS 15-year	MACRS 15-year	N/A	MACRS 5-year	MACRS 5-year
Avoidable Cost	PJM 2019/2020 ACR Defaults	PJM 2019/2020 ACR Defaults	EPA Base Case v5.13	EPA Base Case v5.13	NREL ATB 2015 - 2018 Technology year	NREL ATB 2015 - 2018 Technology year
Heat Rate (Btu/KWh)	6,800[1]	10,300[1]	10,452			
Capacity Factor	Dispatchable within Model				NREL 2006 hourly shapes	NREL 2006 hourly shapes
Fuel Forecast	ABB Fall 2015 Fuel Forecast					
Locational Costs Adders	Brattle 2014 PJM Costs of New Entry study	Brattle 2014 PJM Costs of New Entry study	EIA energy market module NERC sub-regions		EIA energy market module NERC sub-regions	EIA energy market module NERC sub-regions

[1] Varies by PJM Locational Deliverability Region (GE 7FA technology)

Primary Data Sources

- Federal and State Energy Policy and Incentives:
  http://programs.dsireusa.org/system/program/
- EPA Generating Unit and Financial Assumptions:
  https://www.epa.gov/airmarkets/power-sector-modeling-platform-v513
- Natural Gas Combined Cycle and Combustion Turbine Financial Assumptions:
  https://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx
- Solar and Wind Financial Assumptions:
  http://www.nrel.gov/docs/fy15osti/64077-DA.xlsm
- Solar Hourly Shapes:
  http://www.nrel.gov/electricity/transmission/solar_integration_methodology.html
- Wind Hourly Shapes:
  http://www.nrel.gov/electricity/transmission/wind_integration_dataset.html
- Variable Resource Requirement Curve and RPM Planning Parameters:
  http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-bra-planning-parameters.ashx

2019/2020 RPM Base Residual Auction Results

Executive Summary

The 2019/2020 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 167,305.9 MW of unforced capacity in the RTO. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2019/2020 Delivery Year as procured in the BRA is 22.4%, or 5.9% higher than the target reserve margin of 16.5%. This reserve margin was achieved at Capacity Performance prices that are between approximately 33% to 60% of Net CONE, depending upon the zone comparison, while attracting just over 5,000 MW of new combined cycle gas resources.

The 2019/2020 RPM BRA was the second BRA to include the Capacity Performance ("CP") provisions approved by FERC prior to last year's 2018/2019 BRA. As part of the transition to 100% CP starting with next year's 2020/2021 BRA, PJM procured two capacity product types through the auction, Capacity Performance and Base Capacity. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year; whereas, Base Capacity Resources may not be capable of sustained, predictable operation and/or may not be expected to provide energy and reserves outside of the summer period. Base Capacity Resources include Base Capacity Demand Resources (DR), which are expected to be available only during the summer months, and Base Capacity Energy Efficiency (EE) Resources, which are expected to provide permanent continuous load reduction only during the summer months. Base Capacity Resources also include Base Capacity Generation Resources, which are expected to be available throughout the Delivery Year like all Capacity Performance Resources. But, unlike Capacity Performance Resources, Base Capacity Generation Resources will be subject to non-performance charges only when they fail to perform when needed during the summer months.

Base Capacity Resources do not provide the same level of availability or reliability as CP Resources, therefore constraints are imposed on the quantity of Base Capacity Resources that can be procured in each RPM auction. A Base Capacity DR Constraint which places a maximum limit on the total quantity of Base Capacity DR and Base Capacity EE that can be procured in the auction is established for the entire RTO and each modeled LDA. A Base Capacity Resource Constraint which places a maximum limit on the total quantity of Base Capacity DR, Base Capacity EE and Base Capacity Generation Resources that can be procured in the auction is established for the entire RTO and each modeled LDA. If these constraints are reached in the auction then these less-available resources will clear the auction at a lower clearing price then the clearing price associated with similarly located more-available resources.

2019/2020 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2019/2020 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $100.00/MW-day. The EMAAC LDA, ComEd LDA and BGE LDA were constrained LDAs in the 2019/2020 BRA with locational price adders of $19.77/MW-day, $102.77/MW-day and $0.30/MW-day, respectively, for all resources located in those LDAs. The RCP for CP Resources in the EMAAC LDA is $119.77/MW-day, the RCP for CP Resources in the COMED LDA is $202.77 /MW-day, and the RCP for CP Resources located in the BGE LDA is $100.30/MW-day. For comparison purposes, the RCP

2019/2020 RPM Base Residual Auction Results

for CP Resources located in the rest of RTO in the 2018/2019 BRA was $164.77/MW-day. The RCP for CP Resources in the EMAAC LDA was $225.42/MW-day and the RCP for CP Resources in the COMED LDA was $215.00 /MW-day in the 2018/2019 BRA. The BGE LDA cleared with the rest of RTO with a RCP for CP Resources of $164.77/MW-day in the 2018/2019 BRA.

	2019/20 BRA Resource Clearing Prices ($/MW-day)				
Capacity Type	Rest of RTO	EMAAC	PEPCO	COMED	BGE
Capacity Performance	$100.00	$119.77	$100.00	$202.77	$100.30
Base Generation	$80.00	$99.77	$80.00	$182.77	$80.30
Base DR/EE	$80.00	$99.77	$0.01	$182.77	$80.30

The Base Capacity Resource Constraint is a binding constraint in the auction for the overall RTO resulting in a price decrement for Base Capacity Generation of $20.00/MW-day relative to the RCP of similarly located CP resources. Additionally, the Base Capacity DR Constraint is a binding constraint in the PEPCO LDA resulting in price decrements for Base Capacity DR and EE located in the PEPCO LDA of $79.99/MW-day. The price decrement for Base Capacity DR and EE is relative to the RCP of Base Capacity Generation Resources located in the PEPCO LDA.

The RCP for Base Capacity Resources located in the rest of RTO outside of the EMAAC, COMED and BGE LDAs is $80.00/MW-day. The RCP for Base Capacity Resources located in the EMAAC LDA is $99.77/MW-day, the RCP for Base Capacity Resources located in the ComEd LDA is $182.77/MW-day, and the RCP for Base Capacity Resources located in the BGE LDA is $80.30/MW-day. The RCP for Base Capacity DR & EE Resources located in the PEPCO LDA is $0.01/MW-day. The Base DR/EE RCP in PEPCO is a function of the quantity of supply that effectively offered as price takers relative to the Base DR/EE constraint of 474.5 MW.

2019/2020 BRA Cleared Capacity Resources

As seen in the table below, the 2019/2020 BRA procured 5,373.6 MW of capacity from new generation and 155.6 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2019/2020 BRA is 3,875.9 MW which is a decrease of 812 MW from that procured in last year’s BRA. Of the 3,875.9 MW procured from external Generation Capacity Resources in the 2019/2020 BRA, 2,744.7 MW cleared as Capacity Performance product type and 1,131.2 MW cleared as Base product type. All external generation capacity that has cleared in the 2019/20 BRA has met the requirements for the Capacity Import Limit (CIL) exception. The total quantity of DR procured in the 2019/2020 BRA is 10,348 MW which is a decrease of 736.4 MW from that procured in last year’s BRA; and, the total quantity of EE procured in the 2019/2020 BRA

2019/2020 RPM Base Residual Auction Results

is 1,515.1 MW, which is an increase of 268.6 MW from that procured in last year's BRA. Of the 10,348 MW procured from DR Resources in the 2019/2020 BRA, 613.7 MW cleared as Capacity Performance product type and 9,734.3 MW cleared as Base product type. Of the 1,515.1 MW procured from EE Resources in the 2019/2020 BRA, 1,058.1 MW cleared as Capacity Performance product type and 457 MW cleared as Base product type.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2019/2020 BRA

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

2019/2020 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2019/2020 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2019/2020 BRA opened on May 11, 2016, and the results were posted on May 24, 2016.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Constraints on the procurement of the more limited capacity product types are established for the RTO and each modeled LDA. The Base Capacity DR Constraint limits the quantity of Base Capacity DR and EE that can be procured in each LDA or in total across the entire RTO; and the Base Capacity Resource Constraint limits the quantity of the sum of Base Capacity DR and EE and Base Capacity Generation Resources that can be procured in each LDA or in total across the entire RTO.
- Capacity Import Limits (CILs) are established on the amount of external generation capacity that can be reliably committed to PJM. A separate CIL is established for each of five external source-zones and a single total CIL is established for the overall RTO. As described in more detail later in this report, external generation resources may seek exception to the CIL by meeting all three of the following conditions prior to the start of the auction: (1) they are committed to being pseudo-tied generation resources prior to the start of the Delivery Year; that is, they will be treated like internal generation, subject to redispatch and locational pricing; (2) they have long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (3) they agree to be subject to the same capacity must-offer requirement as PJM's internal resources.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resource out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2019/2020 BRA results and a discussion of the results in the context of the ten previous BRAs.

2019/2020 RPM Base Residual Auction Results

Summary of Results

The 2019/2020 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 167,305.9 MW of unforced capacity in the RTO representing a 22.9% reserve margin. The reserve margin for the entire RTO is 22.4%, or 5.9% higher than the target reserve margin of 16.5%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2019/2020 BRA are shown in Table 4. The RCP for CP Resources located in the rest of RTO is $100.00/MW-day. The EMAAC LDA, ComEd LDA and BGE LDA were constrained LDAs in the 2019/2020 BRA. The RCP for CP Resources in the EMAAC LDA is $119.77/MW-day, the RCP for CP Resources in the COMED LDA is $202.77 /MW-day, and the RCP for CP Resources located in the BGE LDA is $100.30/MW-day. For comparison purposes, the RCP for CP Resources located in the rest of RTO in the 2018/2019 BRA was $164.77/MW-day. The RCP for CP Resources in the EMAAC LDA was $225.42/MW-day and the RCP for CP Resources in the COMED LDA was $215.00 /MW-day in the 2018/2019 BRA. The BGE LDA cleared with the rest of RTO with a RCP for CP Resources of $164.77/MW-day in the 2018/2019 BRA.

The Base Capacity Resource Constraint is a binding constraint in the auction for the overall RTO resulting in a price decrement for Base Capacity Generation of $20.00/MW-day relative to the RCP of similarly located CP resources. Additionally, the Base Capacity DR Constraint is a binding constraint in the PEPCO LDA resulting in a price decrement for Base Capacity DR and EE of $79.99/MW-day relative to RCP of Base Capacity Generation Resources located in the PEPCO LDA.

The RCP for Base Capacity Resources located in the rest of RTO is $80.00/MW-day. The RCP for Base Capacity Resources located in the EMAAC LDA is $99.77/MW-day, the RCP for Base Capacity Resources located in the ComEd LDA is $182.77/MW-day, and the RCP for Base Capacity Resources located in the BGE LDA is $80.30/MW-day. The RCP for Base Capacity DR & EE Resources located in the PEPCO LDA is $0.01/MW-day.

The total quantity of new Generation Capacity Resources offered into the auction was 6,543.5 MW (UCAP) comprised of 6,330.1 MW of new generation units and 213.4 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 5,529.2 MW (UCAP) comprised of 5,373.6 MW (UCAP) from new generation units and 155.6 MW from uprates to existing generation units.

The quantity of capacity procured from external Generation Capacity Resources in the 2019/2020 BRA is 3,875.9 MW which is a decrease of 812 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2019/2020 BRA has met the requirements for CIL exception. These requirements help to ensure that external resources offering into the RPM auction

2019/2020 RPM Base Residual Auction Results

have reasonable expectation of physically delivering on any RPM commitment and have high likelihood of being available for PJM when needed.

The total quantity of DR procured in the 2019/2020 BRA is 10,348 MW which is a decrease of 736.4 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2019/2020 BRA is 1,515.1 MW which is an increase of 268.6 MW from that procured in last year's BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

All Generation Capacity Resources (including uprates to existing resources) of 20 MW or greater that are based on combustion turbine, combined cycle and integrated gasification combined cycle technologies that have not cleared an RPM Auction prior to February 1, 2013 are subject to the Minimum Offer Price Rule (MOPR). External Generation Capacity Resources meeting the above criteria and that have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the MOPR, Capacity Market Sellers may request exemption through either a Competitive Entry Exemption request or a Self-Supply Exemption request. The table below shows the requested, granted and cleared aggregate quantity (in ICAP MW) of each exemption type received and processed by PJM. While there were nearly 13,000 MW of MOPR exemption requests, making a request does not obligate a resource to offer into the BRA.

2019/2020 RPM Base Residual Auction Results

LDA	Exemption Type	Requested Quantity (ICAP MW)	Granted Quantity (ICAP MW)	Cleared Quantity (ICAP MW)
RTO*	Competitive Entry	5,401.0	5,401.0	1,933.0
RTO*	Self-Supply	1,827.2	1,827.2	1,779.5
MAAC	Competitive Entry	5,764.0	5,764.0	1,870.9
MAAC	Self-Supply	0.0	0.0	0.0
Total		**12,992.2**	**12,992.2**	**5,583.4**

*RTO values exclude MAAC

A further discussion of the 2019/2020 BRA results and additional information regarding the 2019/2020 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2019/2020 auction results to the results from the 2007/2008 through 2018/2019 RPM Auctions.

2019/2020 RPM Base Residual Auction Results

2019/2020 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2019/2020 RPM BRA in comparison to those from 2007/2008 through 2018/2019 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO												
Auction Results	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012[1]	2012/2013	2013/2014[2]	2014/2015[3]	2015/2016[4]	2016/2017[5]	2017/2018	2018/2019	2019/2020
Resource Clearing Price	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00	$59.37	$120.00	$164.77	$100.00
Cleared UCAP (MW)	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9	167,305.9
Reserve Margin	19.1%	17.4%	17.6%	16.4%	17.9%	20.5%	19.7%	18.8%	19.3%	20.3%	19.7%	19.8%	22.4%

1) 2011/2012 BRA w as conducted w ithout Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2019/2020 RPM BRA cleared 167,305.9 MW of unforced capacity in the RTO representing a 22.9% reserve margin. The reserve margin for the entire RTO is 22.4%, or 5.9% higher than the target reserve margin of 16.5%, when the Fixed Resource Requirement (FRR) load and resources are considered. Moreover, the cleared reserve margin is nearly 2 percent higher than the previous highs observed in the 2012/2013 and 2016/2017 BRAs.

New Generation Resource Participation

The 2019/2020 BRA results reflect a continuation of strong participation by new Generation Capacity Resources mostly in the form of new (or uprates to existing) gas-fired combustion turbine and combined cycle generation units. The total quantity of new Generation Capacity Resources offered into the auction was 6,543.5 MW (UCAP) comprised of 6,330.1 MW of new generation units and 213.4 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 5,529.2 MW (UCAP) comprised of 5,376.6 MW (UCAP) from new generation units, predominantly natural gas combined cycle and combustion turbines, and 155.6 MW from uprates to existing generation units.

Over the last several years, new generation cleared in RPM auctions has been very successful in meeting its committed in-service dates. For example, in the 2015/2016 Delivery Year, of the 4,575 MW of large, combined cycle units that cleared in RPM, all but 661

2019/2020 RPM Base Residual Auction Results

MW are in-service, and the remainder is expected to be in service by mid-2017. For the upcoming 2016/2017 Delivery Year, all 4,091 MW of new, large, combined cycle generation that cleared in RPM is or will be fully in-service by June 1st. For the 2017/2018 Delivery Year, 3,132 MW of the 4,825 MW of new, large, combined cycle units are on schedule to be fully in service before the Delivery Year. In summary, over 80% of the new, large, combined cycle units that cleared in the RPM auctions for these three Delivery Years are either already in service or on schedule to be in service prior to the Delivery Year for which they initially committed.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing units offered in the auction and capacity actually clearing in the auction. Eighty-four percent of the new generation capacity that offered into the 2019/2020BRA cleared the auction.

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

	Offered			Cleared		
LDA	Uprate	New Unit	Total	Uprate	New Unit	Total
EMAAC	54.8	35.6	**90.4**	13.5	35.6	**49.1**
MAAC	63.8	2,274.5	**2,338.3**	22.5	1,843.3	**1,865.8**
Total RTO	213.4	6,330.1	**6,543.5**	155.6	5,373.6	**5,529.2**

*All MW Values are in UCAP Terms

*MAAC includes EMAAC

**RTO includes MAAC

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Capacity Import Participation

The quantity of capacity imports cleared in the 2019/2020 BRA were 3,875.9 MW (UCAP) which represents a decrease of 812 MW from the imports that cleared in the 2018/2019 BRA. Of the 3,875.9 MW procured from external Generation Capacity Resources in the 2019/2020 BRA, 2,744.7 MW cleared as Capacity Performance product type and 1,131.2 MW cleared as Base product type. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2019/20 BRA has met the requirements for the CIL exception.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	252.0	2,199.2	1,105.6	371.0	415.6	4,343.4
Cleared MW (UCAP)	252.0	2,132.9	866.9	371.0	253.1	3,875.9
Resource Clearing Price ($/MW-day)	$0.00	$0.00	$0.00	$0.00	$0.00	

Note: Cleared MW quantities include resources that received CIL Exception and those associated w ith pre-OATT grandfathered transmission

Demand Resource Participation

The total quantity of DR offered into the 2019/2020 BRA was 11,818 MW (UCAP), representing an increase of 1.2% over the DR that offered into the 2018/2019 BRA. Of the 11,818 MW of total DR that offered in this auction, 10,348 MW cleared. The cleared DR is 736.4 MW less than that which cleared in the 2018/2019 BRA. Of the 10,348 MW procured from DR Resources in the 2019/2020 BRA, 613.7 MW cleared as Capacity Performance product type and 9,734.3 MW cleared as Base product type. Table 3A contains a comparison of the DR Offered and Cleared in 2018/2019 BRA & 2019/2020 BRA represented in UCAP.

Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. Of the 1,650.3 MW of energy efficiency that offered into the 2019/2020 BRA, 1,515.1 MW of EE resources cleared in the auction. Of the 1,515.1 MW procured from EE Resources in the 2019/2020 BRA, 1,058.1 MW cleared as Capacity Performance product type and 457 MW cleared as Base product type.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2019/2020 BRA. Approximately 87.6% of the demand resources and 91.8% of the energy efficiency resources that were offered into the BRA cleared. The uncleared resources were offered at a price above the applicable clearing price for the LDA in which the resource was offered.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2019/2020 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2019/2020 BRA have fallen below the levels seen in the 2014/2015 BRA.

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Table 3A – Comparison of Demand Resources Offered and Cleared in 2018/2019 BRA & 2019/2020 BRA represented in UCAP

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2018/2019	2019/2020	Increase in Offered MW	2018/2019	2019/2020	Increase in Cleared MW
EMAAC	AECO	165.1	153.8	**(11.3)**	162.1	145.7	**(16.4)**
EMAAC/DPL-S	DPL	422.7	397.9	**(24.8)**	418.2	371.6	**(46.6)**
EMAAC	JCPL	206.4	231.2	**24.8**	200.1	200.8	**0.7**
EMAAC	PECO	513.0	565.1	**52.1**	504.5	527.4	**22.9**
PSEG/PS-N	PSEG	386.6	427.8	**41.2**	382.2	380.7	**(1.5)**
EMAAC	RECO	7.6	10.3	**2.7**	7.5	10.3	**2.8**
EMAAC Sub Total		**1,701.4**	**1,786.1**	**84.7**	**1,674.6**	**1,636.5**	**(38.1)**
PEPCO	PEPCO	667.1	570.4	**(96.7)**	523.1	483.3	**(39.8)**
BGE	BGE	813.9	729.3	**(84.6)**	660.0	256.4	**(403.6)**
MAAC	METED	334.9	379.8	**44.9**	327.4	321.7	**(5.7)**
MAAC	PENELEC	392.6	392.0	**(0.6)**	384.7	339.4	**(45.3)**
PPL	PPL	873.6	815.6	**(58.0)**	716.2	739.8	**23.6**
MAAC Sub Total**		**4,783.5**	**4,673.2**	**(110.3)**	**4,286.0**	**3,777.1**	**(508.9)**
RTO	AEP	1,441.5	1,603.1	**161.6**	1,417.6	1,416.1	**(1.5)**
RTO	APS	990.7	1,039.4	**48.7**	976.8	926.0	**(50.8)**
ATSI/ATSI-C	ATSI	891.9	978.0	**86.1**	877.0	897.6	**20.6**
COMED	COMED	1,901.2	1,792.0	**(109.2)**	1,876.7	1,757.4	**(119.3)**
RTO	DAY	234.9	237.6	**2.7**	231.6	219.8	**(11.8)**
RTO	DEOK	205.7	248.8	**43.1**	203.8	236.7	**32.9**
RTO	DOM	827.8	816.8	**(11.0)**	817.3	729.7	**(87.6)**
RTO	DUQ	263.0	286.8	**23.8**	262.3	247.2	**(15.1)**
RTO	EKPC	135.3	142.3	**7.0**	135.3	140.4	**5.1**
Grand Total		**11,675.5**	**11,818.0**	**142.5**	**11,084.4**	**10,348.0**	**(736.4)**

**MAAC sub-total includes all MAAC Zones

2019/2020 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2018/2019 BRA

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	153.8	18.6	**172.4**	145.7	14.1	**159.8**
EMAAC/DPL-S	DPL	397.9	25.7	**423.6**	371.6	22.4	**394.0**
EMAAC	JCPL	231.2	26.1	**257.3**	200.8	21.2	**222.0**
EMAAC	PECO	565.1	50.2	**615.3**	527.4	41.1	**568.5**
PSEG/PS-N	PSEG	427.8	59.6	**487.4**	380.7	49.3	**430.0**
EMAAC	RECO	10.3	25.3	**35.6**	10.3	12.7	**23.0**
EMAAC Sub Total		**1,786.1**	**205.5**	**1,991.6**	**1,636.5**	**160.8**	**1,797.3**
PEPCO	PEPCO	570.4	85.2	**655.6**	483.3	79.0	**562.3**
BGE	BGE	729.3	100.7	**830.0**	256.4	100.7	**357.1**
MAAC	METED	379.8	20.7	**400.5**	321.7	18.2	**339.9**
MAAC	PENELEC	392.0	26.1	**418.1**	339.4	17.3	**356.7**
PPL	PPL	815.6	56.8	**872.4**	739.8	50.9	**790.7**
MAAC Sub Total**		**4,673.2**	**495.0**	**5,168.2**	**3,777.1**	**426.9**	**4,204.0**
RTO	AEP	1,603.1	76.6	**1,679.7**	1,416.1	72.0	**1,488.1**
RTO	APS	1,039.4	29.0	**1,068.4**	926.0	26.8	**952.8**
ATSI/ATSI-C	ATSI	978.0	52.8	**1,030.8**	897.6	41.0	**938.6**
COMED	COMED	1,792.0	725.1	**2,517.1**	1,757.4	724.8	**2,482.2**
RTO	DAY	237.6	25.9	**263.5**	219.8	24.5	**244.3**
RTO	DEOK	248.8	31.2	**280.0**	236.7	24.4	**261.1**
RTO	DOM	816.8	190.2	**1,007.0**	729.7	152.0	**881.7**
RTO	DUQ	286.8	15.2	**302.0**	247.2	14.1	**261.3**
RTO	EKPC	142.3	9.3	**151.6**	140.4	8.6	**149.0**
Grand Total		**11,818.0**	**1,650.3**	**13,468.3**	**10,348.0**	**1,515.1**	**11,863.1**

**MAAC sub-total includes all MAAC Zones

Any resource that can qualify as a CP Resource may submit separate but coupled sell offers for CP and Base Capacity product types. When sell offer segments of both capacity product types are coupled with different offer prices, the auction clearing engine will clear only one of the products at most and will clear the product that results in the lowest cost solution for the system. Any Generation Capacity Resource with a unit-specific MSOC above the CP default MSOC must submit separate but coupled sell offers for CP and Base Capacity product types. Table 3C shows a breakdown of offered and cleared capacity for each resource type grouped by

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coupling scenario. As shown on Table 3C, 138,635.5 MW or 89.2% of the total cleared generation capacity cleared as CP; 613.7 MW or 5.9% of the total cleared DR capacity cleared as CP; and, 1,058.1 MW or 69.8% of total cleared EE capacity cleared as CP.

Table 3C – Breakdown of Capacity Resources Offered versus Cleared by Product Type in the 2018/19 BRA in UCAP

		Offered MW (UCAP)		Cleared MW (UCAP)	
Resource Type	Product Coupling Scenario	Base Product Type	Capacity Performance Product Type	Base Product Type	Capacity Performance Product Type
GEN	Capacity Performance and Base	26,221.3	26,821.4	11,831.2	12,236.2
GEN	Capacity Performance Only	-	140,219.9	-	126,399.3
GEN	Base Only	5,023.0	-	4,976.1	-
GEN Sub Total		**31,244.3**	**167,041.3**	**16,807.3**	**138,635.5**
DR	Capacity Performance and Base	4,659.4	4,317.6	3,961.9	266.7
DR	Capacity Performance Only	-	404.0	-	347.0
DR	Base Only	6,656.9	-	5,772.4	-
DR Sub Total		**11,316.3**	**4,721.6**	**9,734.3**	**613.7**
EE	Capacity Performance and Base	582.3	582.4	45.2	517.0
EE	Capacity Performance Only	-	541.1	-	541.1
EE	Base Only	526.1	-	411.8	-
EE Sub Total		**1,108.4**	**1,123.5**	**457.0**	**1,058.1**
Grand Total		**43,669.0**	**172,886.4**	**26,998.6**	**140,307.3**

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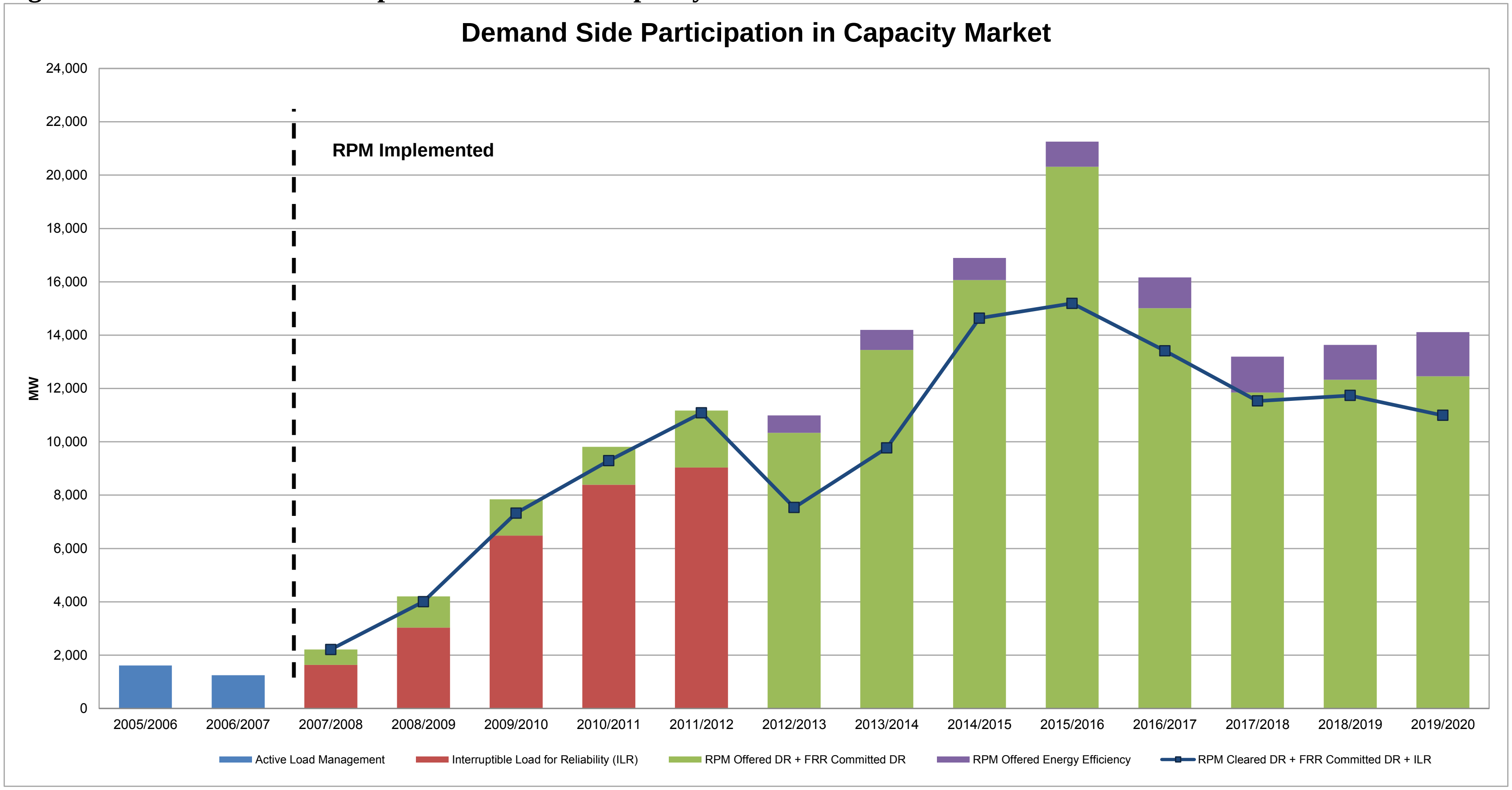
Figure 1 – Demand Side Participation in the PJM Capacity Market



2019/2020 RPM Base Residual Auction Results

Renewable Resource Participation

969 MW of wind resources were offered into and cleared the 2019/2020 BRA as compared to 857.2 MW of wind resources that offered into and cleared the 2018/2019 BRA. The capacity factor applied to wind resources is 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 969 MW of cleared wind capacity translates to 7,453.8 MW of wind energy nameplate capability that is expected to be available in the 2019/2020 Delivery Year. Of the 969 MW procured from wind resources in the 2019/2020 BRA, 89.4 MW cleared as Capacity Performance product type and 879.6 MW cleared as Base product type.

335 MW of solar resources were offered into and cleared the 2019/2020 BRA as compared to 183.7 MW of solar resources that offered into and cleared the 2018/2019 BRA. The capacity factor applied to solar resources is 38%, meaning that for every 100 MW of solar energy, 38 MW are eligible to meet capacity requirements. The 335 MW of cleared solar capacity translates to 881.6 MW of nameplate solar energy capability that is expected to be available in the 2019/2020 Delivery Year. Of the 335 MW procured from solar resources in the 2019/2020 BRA, 0.4 MW cleared as Capacity Performance product type and 334.6 MW cleared as Base product type.

LDA Results

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE and PL were modeled as LDAs in the 2019/2020 RPM Base Residual Auction. The EMAAC LDA, ComEd LDA and BGE LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

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Table 4 contains a summary of the clearing results in the LDAs from the 2019/2020 RPM Base Residual Auction.

Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED
Offered MW (UCAP)	185,539.5	74,633.0	13,299.9	6,786.6	4,100.7	33,228.2	1,721.4	6,634.0	3,726.5	11,847.7	2,486.7	12,106.3	26,588.7
Cleared MW (UCAP)	167,305.9	64,915.0	11,394.6	6,248.4	2,739.5	30,769.3	1,598.5	5,455.0	3,205.3	10,291.1	2,089.0	9,649.6	22,971.4
System Marginal Price	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00
Locational Price Adder*	-	-	-	-	$0.30	$19.77	$19.77	$19.77	$19.77	-	-	-	$102.77
Base Capacity Resource Price Decrement**	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)	($20.00)
Base DR/EE Capacity Price Decrement	-	-	-	($79.99)	-	-	-	-	-	-	-	-	-
RCP for Base DR/EE Resources	$80.00	$80.00	$80.00	$0.01	$80.30	$99.77	$99.77	$99.77	$99.77	$80.00	$80.00	$80.00	$182.77
RCP for Base Generation Resources	$80.00	$80.00	$80.00	$80.00	$80.30	$99.77	$99.77	$99.77	$99.77	$80.00	$80.00	$80.00	$182.77
RCP for Capacity Performance Resources	$100.00	$100.00	$100.00	$100.00	$100.30	$119.77	$119.77	$119.77	$119.77	$100.00	$100.00	$100.00	$202.77

*Locational Price Adder is w ith respect to the immediate parent LDA

**Base Generation and Base DR/EE receive the Base Capacity Resource Price Decrement

Since the EMAAC LDA, ComEd LDA and BGE LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2019/2020 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

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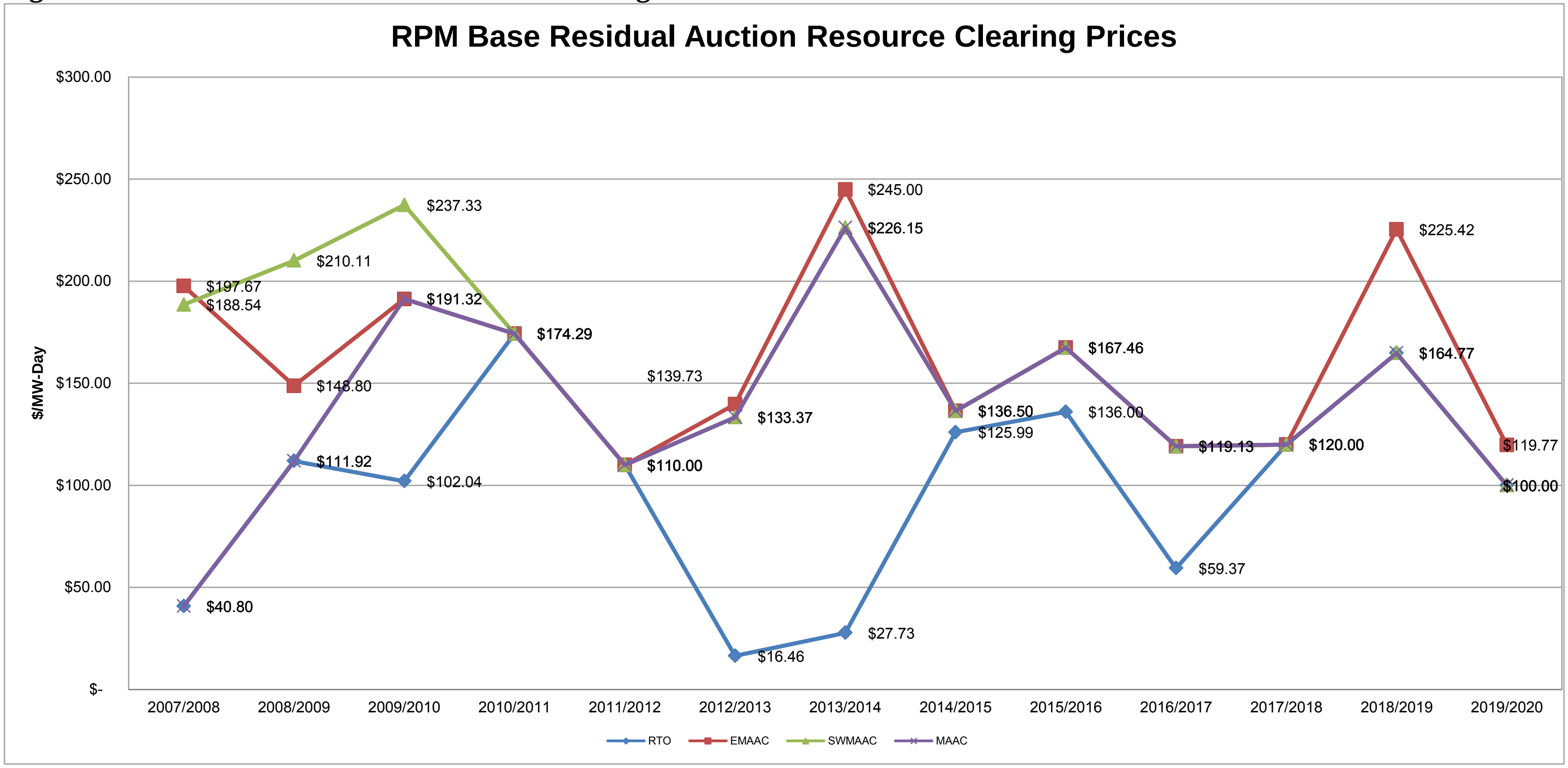
2019/2020 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



*2014/2015 through 2019/2020 Prices reflect the Annual Resource Clearing Prices.

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Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2019/2020 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 212,401 MW of installed capacity was eligible to be offered into the 2019/2020 Base Residual Auction, with 4,821.4 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2019/2020 auction increased by 4.8 MW from that of the previous auction and FRR commitments decreased by 407.7 MW from the 2018/2019 Delivery Year to 15,385.3 MW.

A total of 194,243 MW of capacity was offered into the Base Residual Auction. This is an increase of 4,672.6 MW from that which was offered into the 2018/2019 BRA. A total of 18,158 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests not yet reflected in eRPM, and excess capacity owned by an FRR entity.

2019/2020 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

	RTO[1]											
Auction Supply (all values in ICAP)	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012[2]**	**2012/2013**	**2013/2014[3]**	**2014/2015[4]**	**2015/2016[5]**	**2016/2017[6]**	**2017/2018**	**2018/2019**	**2019/2020**
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1]RTO numbers include all LDAs.

[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

[3]2013/2014 includes ATSI zone and generation

[4]2014/2015 includes Duke zone and generation

[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative

[6]2016/2017 includes EKPC zone

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Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate DR Factor and Forecast Pool Requirement (FPR) for the Delivery Year.

In UCAP terms, a total of 185,539.5 MW were offered into the 2019/2020 BRA, comprised of 172,071.2 MW of generation capacity, 11,818 MW of capacity from DR, and 1,650.3 MW of capacity from EE resources. Of those offered, a total of 167,305.9 MW of capacity was cleared in the BRA.

Of the 167,305.9 MW of capacity that cleared in the auction, 155,442.8 MW were from Generation Capacity Resources, 10,348 MW were from DR, and 1,515.1 MW were from EE resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2019/2020 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

	RTO*											
Auction Results (all values in UCAP)**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0
EE Offered	-	-	-	-	652.7	756.8	831.9	940.3	1,156.8	1,340.0	1,306.1	1,650.3
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2019/2020 BRA. A total of 6,327.8 MW of incrementally new capacity in PJM was available for the 2019/2020 BRA. This incrementally new capacity includes new Generation Capacity Resources and capacity upgrades to existing Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources and an increase in the quantity of offered DR and EE to yield a net increase of 3,803.0 MW of installed capacity.

Table 7 also illustrates the total amount of resource additions and reductions over twelve Delivery Years since the implementation of the RPM construct. Over the period covering the first thirteen RPM BRAs, 46,534.5 MW of new generation capacity was added, which was partially offset by 36,623.4 MW of capacity de-ratings or retirements over the same period. Additionally, 11,297 MW of new DR and 1,517.4 MW of new EE resources were offered over the course of the thirteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last thirteen RPM auctions was 22,725.5 MW.

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*													
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014[1]**	**2014/2015[2]**	**2015/2016**	**2016/2017[3]**	**2017/2018**	**2018/2019**	**2019/2020**	**Total**
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	1,582.8	8,207.0	6,806.0	6,973.3	5,055.6	6,327.8	46,534.5
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-1,924.1	-1,550.1	-6,432.6	-4,992.0	-9,760.1	-3,620.8	-2,923.1	-36,623.4
Net Increase in Demand Resource	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	2,514.4	4,200.5	-5,310.7	-3,077.7	-82.4	86.4	11,297.0
Net Increase in Energy Efficiency	0.0	0.0	0.0	0.0	0.0	632.3	101.1	73.1	101.3	204.8	176.4	-83.5	311.9	1,517.4
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1503.1**	**3973.3**	**7,210.0**	**2,907.8**	**2,620.2**	**6,076.2**	**-3,291.9**	**-5,688.1**	**1,268.9**	**3,803.0**	**22,725.5**

* RTO numbers include all LDAs

** Values are w ith respect to the quantity offered in the previous year's Base Residual Auction.

1) Does not include Existing Generation located in ATSI Zone

2) Does not include Existing Generation located in Duke Zone

3) Does not include Existing Generation located in EKPC Zone

Table 7A provides a further breakdown of the generation increases and decreases for the 2019/2020 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2019/2020Delivery Year

LDA Name	Increases	Decreases
EMAAC	93.0	(1,275.4)
MAAC	2,508.9	(1,736.7)
Total RTO	**6,327.8**	**(2,923.1)**

All Values in ICAP terms

*MAAC includes EMAAC

**RTO includes MAAC

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Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant quantity of generating capacity from new resources and uprates to existing resources offered into the 2019/2020 BRA. The capacity offered in the 2019/2020 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, coal, wind, and nuclear resources. The largest growth remains in gas turbines and combined cycle plants.

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Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2019/2020

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3						19.0
	2008/2009			27.0					66.1		93.1
	2009/2010	399.5		23.8		53.0					476.3
	2010/2011	283.3	580.0	23.0					141.4		1,027.7
	2011/2012	416.4	1,135.0			704.8		1.1	75.2		2,332.5
	2012/2013	403.8		7.8		621.3			75.1		1,108.0
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7		1,320.2
	2014/2015	108.0	650.0	35.1	132.9			28.0	146.6		1,100.6
	2015/2016	1,382.5	5,914.5	19.4	148.4	45.4		13.8	104.9	30.0	7,658.9
	2016/2017	171.1	4,994.5	38.3		24.0		32.1	54.3		5,314.3
	2017/2018	131.0	5,010.0	124.8	6.0	90.0		27.0			5,388.8
	2018/2019	1,032.5	2,352.3	29.9				82.8	127.1		3,624.6
	2019/2020	167.0	6,145.0	29.9				152.3	73.0		6,567.2
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0					47.0
	2008/2009					131.0					131.0
	2009/2010										-
	2010/2011	160.0		10.7							170.7
	2011/2012	80.0				101.0					181.0
	2012/2013										-
	2013/2014										-
	2014/2015			9.0							9.0
	2015/2016										-
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
	2019/2020										-
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0				536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4				500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5		796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3				577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7		1,062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8		785.5
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6		417.3
	2014/2015	104.9		0.5	41.5	138.6	107.0	7.1	73.6		473.2
	2015/2016	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		548.1
	2016/2017	436.6	420.0	3.3	7.4	484.3	102.6	1.7	14.8		1,470.7
	2017/2018	71.9	212.5	5.1	105.9	64.8	11.0	0.4	2.1		473.7
	2018/2019	33.4	548.0	2.4	22.9	11.9	79.3	-	14.9	-	712.8
	2019/2020	29.3	72.5	3.9	5.2	65.3			46.8		223.0
	Total	7,106.0	29,586.2	527.1	882.2	4,859.8	1,402.3	358.0	1,407.3	30.0	46,158.9

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Figure 4: Cumulative Generation Capacity Increases by Fuel Type

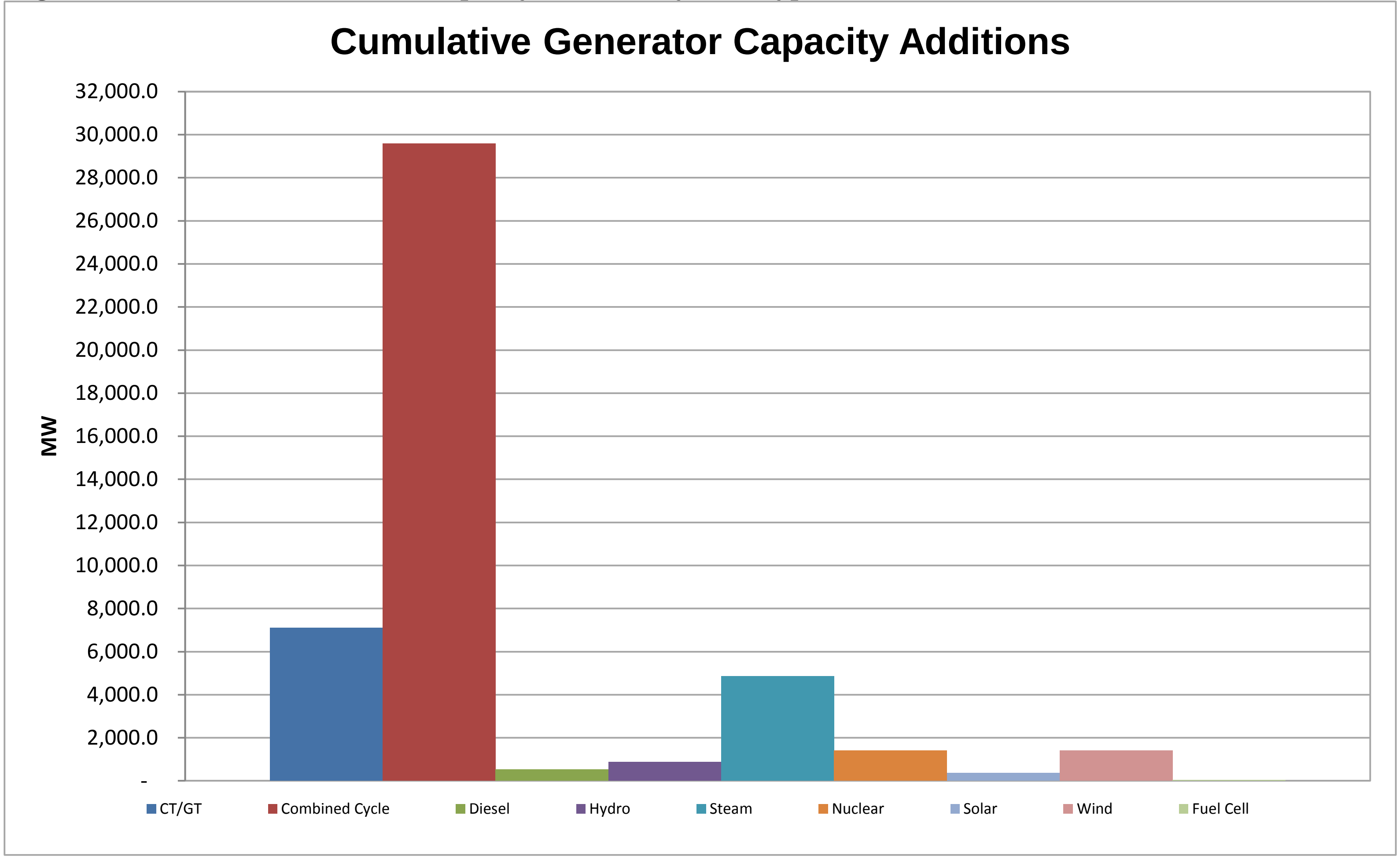

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Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2019/2020 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 4,938.4 MW of cleared UCAP in the 2019/2020 BRA which equates to 7,067.5 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008

	RTO*	
Generation Resource Decision Changes	ICAP Offered	UCAP Cleared
Withdrawn Deactivation Requests	2,202.7	1,085.4
Postponed or Cancelled Retirement	3,571.7	3,138.5
Reactivation	1,293.1	714.5
Total	**7,067.5**	**4,938.4**

RPM Impact to Date

As illustrated in Table 5, for the 2019/2020 auction, the capacity exports were 1,318.2 MW and the offered capacity imports were 4,821.4 MW. The difference between the capacity imports and exports results is a net capacity import of 3,503.2 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 3,503.2 MW. Therefore, RPM's impact on PJM capacity interchange is 6,119.2 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2019/2020 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2019/2020 compared to what would have happened absent this implementation is 65,092.5 MW.

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Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

Change in Capacity Availability	Installed Capacity MW
New Generation	36,031.2
Generation Upgrades (not including reactivations)	8,577.0
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	12,814.4
Cleared ICAP from Withdrawn or Cancelled Retirements	-
Net increase in Capacity Imports	6,119.2
Total Impact on Capacity Availability in 2019/2020 Delivery Year	**65,092.5**

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Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2019/2020 RPM BRA clearing prices relative to 2018/2019 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

Changes that impacted the Demand Curve:

- The target reliability requirement for the 2019/2020 BRA is 158,984 MW, which is 1,624 MW (1.0%) lower than the target reliability requirement of the 2018/2019 BRA of 160,607 MW.

Changes that impacted the Supply Curve:

- Unlike previous BRAs, there are no major environmental rules that are imminent in implementation for the 2019/2020 Delivery year, though there are permit renewal issues and state specific implementation of environmental rules to consider on items such as coal ash, cooling water intake structures, and updated NAAQS standards that are on the horizon for many existing resources. The now stayed EPA Clean Power Plan would not take effect until 2022, at the earliest, if upheld, which would only have its first effect for the 2021/2022 BRA to be held in 2018.
- In theory, with the transition to the Capacity Performance product, the implied costs of committing to be a Capacity Resource increases due to the need to make improvements in generator performance during Performance Assessment Hours. These increased costs could be related weatherization, improved maintenance, and costs for fuel assurance. One should then expect an upward and leftward shift in the resource supply curve leading to higher capacity market prices overall, all else equal. However, observed offer behavior and discussions with some generation owners since Capacity Performance has been implemented indicate that such costs are lower than expected. In particular, the use of third party marketers to help firm up gas supplies has provided options for ensuring performance that may not have been contemplated prior to Capacity Performance.
- Intuitively one would expect low natural gas prices and low overall energy demand, which have led to lower energy market prices, have also led to lower net energy market revenues across the PJM system, especially for coal and oil steam units as well as nuclear units. Such conditions should be expected to lead to higher capacity market offers from these resources to at least cover going forward costs.

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- Relative to last year, there were more new resources offered in the BRA and cleared than the previous year and overall there was more than 4,500 MW of additional resources offered in the 2019/2020 BRA than in the previous year. This has the effect of shifting the supply curve down and to the right which would lower prices, all else equal.