Rebuttal Testimony, Exhibits and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

Surry-Skiffes Creek 500 kV Transmission Line

Skiffes Creek-Whealton 230 kV Transmission Line

Skiffes Creek 500 kV-230 kV-115 kV Switching Station

Application No. 257

Case No. PUE-2012-00029

Filed: March 14, 2013

PUBLIC VERSION

VOLUME I OF VI

Hathaway

REBUTTAL TESTIMONY
OF
SCOT C. HATHAWAY
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-201200029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. I am Scot C. Hathaway, and I am Vice President of Electric Transmission for Dominion Virginia Power. My office is located at 120 Tredegar Street, Richmond, Virginia.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, my pre-filed direct testimony on behalf of Dominion Virginia Power was submitted to the Virginia State Corporation Commission (the "Commission") in this matter on June 11, 2012.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to comment on the direct testimony submitted by the Commission Staff ("Staff") in this proceeding and to address the current state of the electric transmission system in the North and South Hampton Roads Load Areas. I will also generally respond to the recommendations of James City County (or "JCC") Witnesses Waine P. Whittier, Robert Middaugh, Richard Schreiber, William Street, William M. Kelso, and Tamara Rosario, as adopted by JCC Witness Leanne Reidenbach, (collectively, the "JCC witnesses") contained in their direct testimonies in this proceeding that the Commission require that any transmission line crossing of the James River to Skiffes Creek Switching Station ("Skiffes Station") as part of the proposed Project be constructed underground at 230 kV. In doing so, I will generally address public witness comments as to undergrounding the line crossing of the James River and the Hearing Examiner's directive to the Company issued during the January 10, 2013 public hearing and raised by the additional analyses ("Additional Analyses") conducted pursuant to the Hearing Examiner's January 30, 2013 Ruling ("January 30 Ruling") that the Company present evidence regarding the feasibility, cost and advisability of a number of 230 kV alternatives.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, SCH, consisting of Rebuttal Schedule 1, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Please describe the scope of the Additional Analyses conducted by the Company pursuant to the January 30 Ruling.

A. The Company had studied the issues surrounding underground construction and presented the results of its analysis through the Appendix included with its Application. However, Staff Witness John W. Chiles suggested additional studies be conducted, which resulted in the Additional Analyses required by the January 30 Ruling. The Additional Analyses required the Company to look at alternatives with 230 kV underground construction, rebuilding of 230 kV lines in the area, 230 kV transmission in combination with retention of or new generation at Yorktown Power Station ("Yorktown"), and stand-alone generation options at Yorktown. These Additional Analyses have been conducted, the results of which are presented in the rebuttal testimonies of Company Witnesses Peter Nedwick (study results), Mark S. Allen (cost of overhead portions, time to construct all

230 kV alternatives), Walter R. "Trey" Thomasson, III (cost of underground portions), Glenn A. Kelly (cost of retrofitted, repowered and new generation and unavailability of natural gas) and Elizabeth P. Harper (routing considerations). The results of these witnesses' extensive efforts conducted over the prior several weeks are summarized in my Rebuttal Schedule 1, which shows by any measure, be it ability to meet the needs of the North Hampton Roads Load Area, cost or timeliness, the Project is still the most reliable, responsible and reasonable solution for our customers. The Project optimally maintains and protects the integrity and reliability of the transmission system and its construction has been approved in PJM Interconnection, L.L.C.'s ("PJM") 2012 Regional Transmission Expansion Plan ("RTEP"), which has identified the need for the construction of the proposed Project by the summer of 2015 to relieve violations of mandatory NERC Reliability Standards ("NERC Reliability Violations" or "Reliability Violations").

Q. How are these Additional Analyses defined?

A. The Company conducted the following Additional Analyses that are defined and grouped as follows:

- Alternative A: underground 230 kV hybrid single circuit (1000 MVA) on James River Crossing Variation 3 Hybrid conceptual route[1].
- 230 kV Alternative A + generation: Alternative A and generation at Yorktown that electrically resolves the NERC Reliability Violations.
- Alternative B: underground 230 kV hybrid double circuit (1000 MVA/circuit) on James River Crossing Variation 3 Hybrid conceptual route[2].
- 230 kV Alternative B + generation: Alternative B and generation at Yorktown that electrically resolves the NERC Reliability Violations.

[1] As directed by the Hearing Examiner, Alternatives A and B are to come ashore underground on the BASF property at the James River Crossing Variation 3 and then continue underground on that route to an underground-overhead transition station at BASF Drive and then continue overhead on that route along BASF Drive to Skiffes Station.
[2] *See, supra,* n.1.

- Alternative C: rebuild of the existing James River crossing of 230 kV Lines #214 and #263 between the Isle of Wight County and the City of Newport News.
- 230 kV Alternative C + generation: Alternative C and generation at Yorktown that electrically resolves the NERC Reliability Violations.
- Stand-Alone Generation Option: amount of generation at Yorktown without additional transmission facilities that electrically resolves the NERC Reliability Violations.

Q. Can you discuss the direct testimony of the Staff?

A. Yes. The Staff hired two independent expert consultants to review the Company's Application in this proceeding. One consultant, John W. Chiles, Principal-GDS Associates, Inc. ("GDS"), was hired to provide an independent analysis of the need for the Project and to provide the Commission with analysis of GDS-developed alternatives to the Project. A second consultant, Wayne D. McCoy, President of Mid Atlantic Environmental LLC ("MAE"), was hired to conduct an independent routing and environmental assessment of the proposed Project, a report which was provided to the Commission on January 11, 2013 ("MAE Routing and Environmental Report") and attached to Mr. McCoy's testimony as Exhibit WDM-1. Staff Witness McCoy also submitted to the Commission on January 11, 2013, a report on environmental regulations associated with the proposed Project ("MAE Environmental Regulations Report"), which is attached to his testimony as Exhibit WDM-2.

Q. Please describe the Company's assessment of the GDS need analysis.

A. The Company is pleased that Staff Witness Chiles was "able to verify the Company's power flow results," was able to "conclude[] that the Project adequately addresses the Company's identified reliability needs," and find that "none of the 230 kV alternatives are viable alternatives to the Project in terms of meeting the identified reliability need."

(Staff Witness Chiles Direct Testimony at 16, 31, and 24). In addition, Staff Witness Chiles made the following findings:

- From a short-term reliability perspective, a double circuit 230 kV overhead Surry-Skiffes Creek line is comparable to the Project's 500 kV line, but from a long-term perspective, such a 230 kV line does not provide thermal capacity comparable to that of the Project's 500 kV line. Therefore, Staff Witness Chiles does not recommend construction of a double circuit 230 kV Surry-Skiffes Creek line, as it is "less effective than the Project." (Staff Witness Chiles Direct Testimony at 32-33).

- A double circuit underground 230 kV Surry-Skiffes Creek hybrid line "has shortcomings that do not exist with either the double-circuit 230 kV overhead line or the 500 kV line. Although this alternative's shortcomings can likely be resolved (e.g., adding more pipes would increase the capacity of the underground segment), the additional cost and practicality weighs against such an option." Therefore, Staff Witness Chiles does not recommend the construction of a 230 kV Surry-Skiffes Creek underground hybrid line (either single or double circuit) "due to identified reliability issues and expected cost increase and practicality to build for a line capacity equivalent to the proposed 500 kV line." (Staff Witness Chiles Direct Testimony at 32-33).

Q. Does the Company agree with these findings of Staff Witness Chiles?

A. Yes, we do. Staff Witness Chiles's analyses confirmed the need for a solution to the identified mandatory NERC Reliability Violations described in the Company's Application that are projected to occur in 2015, absent construction of the Project. Also, Staff Witness Chiles agrees that no 230 kV alternative, whether single or double circuit – overhead or underground – is a viable alternative for solving the identified need. These findings are consistent with the Company's initial analyses, those conducted by PJM, the regional transmission organization with responsibility for regional transmission reliability, and the Additional Analyses recently concluded.

Q. Did the Company analyze whether a 230 kV alternative could address the Reliability Violations identified in the North Hampton Roads Load Area in this proceeding?

A. We certainly did. As a public utility, Dominion Virginia Power's fundamental purpose is to provide reliable electric service to all of its customers in a safe, responsible and reasonable manner. To fulfill this purpose, the Company embraces the rigorous due process provided through PJM's RTEP and the Commission's certificate of public convenience and necessity proceedings where the Company is required to show need for a transmission solution, the most balanced resolution of that need, and a route that reasonably minimizes known impacts. Company Witness Steven R. Herling, Vice-President for Planning for PJM, discusses PJM's reliability analysis of LS Power's 230 kV proposal and why it failed to resolve the identified Reliability Violations as effectively and economically as the Project. While the JCC witnesses have recommended in this proceeding a 230 kV underground alternative in order to achieve their purpose of proposing an underground "solution" for the James River crossing, the Company's analyses, as confirmed by Staff Witness Chiles, and the Additional Analyses continue to show that the Surry-Skiffes Creek transmission line should be constructed in the form of the more robust and cost-effective 500 kV solution.

Q. Does the proposed Project continue to resolve the need in 2015 better than any 230 kV alternative, 230 kV + Generation Options or Stand-Alone Generation Option?

A. It absolutely does. My Rebuttal Schedule 1 illustrates the results of the Additional Analyses and continues to show the Surry-Skiffes Creek 500 kV proposed Project remains the most reliable, responsible and reasonable solution to the identified Reliability

Violations, both now and in the future. As required by the January 30 Ruling, the Additional Analyses incorporate the PJM 2013 Load Forecast Report and the most up-to-date transmission system configuration. My Rebuttal Schedule 1 shows that, even if they could be constructed in time - - and many cannot - -, Alternative A, Alternative B, Alternative C, any of those Alternatives + generation, and the Stand-Alone Generation Option cost between 3 and 7 times the cost of the Project, when comparing them "apples to apples" based on total costs.

Q. You mentioned that the extension of the 500 kV system into the North Hampton Roads Load Area will provide an opportunity for the Company to responsibly plan for the future. Please elaborate.

A. As detailed in the Company's direct case, the 230 kV systems in the North and South Hampton Roads Load Areas both have significant generation deficiencies, meaning that neither of the 230 kV systems can support the other without further straining its own system. The new transmission facilities proposed by the Company as part of its Project will resolve all of the identified 2015 NERC Reliability Violations by providing a new source of bulk power from the 500 kV system to support the 230 kV system in the North Hampton Roads Load Area and by relieving loading on that system through the addition of a new 230 kV source into the Peninsula east of Skiffes Creek. In addition to providing a solution for the near-term contingencies in 2015, this extension of the 500 kV system into the North Hampton Roads Load Areas will provide a robust response to the longer-term issues on the generation-deficient 230 kV system east of the City of Richmond.

Maintaining future system reliability includes planning to anticipate the effect on the transmission system of projected increases in demand. As further explained by Rebuttal

Schedule 1 to the rebuttal testimony of Company Witness Nedwick, in 2015, under normal operating conditions, the North Hampton Roads Load Area will import 86.6% of its capacity from west of Richmond, while South Hampton Roads will import 52%. These import requirements increase to 99% and 75%, respectively, under critical system conditions in 2015. By summer 2021, the situation in North Hampton Roads is even more severe because it must import 87% of its capacity from west of Richmond under normal operating conditions and 98% under critical system conditions, while these figures for South Hampton Roads increase to 54.6% and 76.6%, respectively.

The implications of these system conditions must be considered in evaluating transmission planning solutions east of Richmond. First, as I mentioned above, the 230 kV systems in the North and South Hampton Roads Load Areas both have significant generation deficiencies, meaning that neither 230 kV system can support the other without further straining its own system. For example, addressing NERC Reliability Violations on the 230 kV system in North Hampton Roads by creating a new 230 kV feed into that load area from South Hampton Roads (e.g., from Surry) would merely increase the supply requirements on the already-stressed 230 kV system in generation-deficient South Hampton Roads. Second, because the City of Richmond area is currently balanced between load and generation, the bulk power requirements for the North and South Hampton Roads Load Areas must come from generation resources located to the west of the City of Richmond. Accordingly, expansion of the 500 kV system in this area (east of Richmond) is needed to maintain reliable service, for both the near and long term, to the Company's customers located in the North and South Hampton Roads Load Areas. The proposed Project will appropriately reinforce the 500 kV system east of the City of

Richmond to provide a new, robust, cost-effective solution for maintaining system reliability in these load areas experiencing significant generation retirements by 2015, as well as provide for robust and reliable system planning in the future.

Q. Staff Witness McCoy opined on page 14 of the MAE Routing and Environmental Report (Exhibit WDM-1) that the Project area "is not an area that can easily absorb a new, large electrical transmission line." Do you agree?

A. I agree that this Project area has unique characteristics which make the routing of this Project particularly challenging. That said, Mr. McCoy's opinion reinforces the Company's proposal to build this Project as a new 500 kV source for the North Hampton Roads Load Area to address the identified reliability need. Constructing this Project at 230 kV would not provide a long-term, robust solution to the identified need because it would simply further strain the South Hampton Roads Load Area to serve the North Hampton Roads Load Area. As a result, and as the testimony of the Staff and JCC witnesses themselves acknowledge and the results of the Additional Analyses show, any 230 kV alternative would require the addition of numerous other facilities to resolve the 2015 NERC Reliability Violations, which add to the cost of the solution as illustrated in my Rebuttal Schedule 1, and raise numerous timing issues on whether the alternative can be built in time to solve the reliability need and be in compliance with environmental regulations. These uncertainties of timing for permitting, construction and environmental compliance must also be seriously considered when weighing the validity of these 230 kV alternatives. On the other hand, the 500 kV solution has been established many times by the Company, PJM and Staff Witness Chiles and again by the Company, using the most recent information available, to be the most reliable, responsible and reasonable solution.

Q. On pages 26-31 of his testimony, Staff Witness Chiles raises questions regarding the analysis conducted by the Company with regard to the existing and new generation in the Project area. How did the Company evaluate the existing and new generation in the Project area?

A. Company Witness Kelly addresses this analysis in greater detail in his rebuttal testimony. As part of its 2011 integrated resource planning ("IRP") process and again as part of the 2012 IRP process, the Company analyzed several of its older coal- and oil-fired generation units (including the units at Yorktown) that must comply with anticipated generation environmental rules, including a review of the comparative costs to retrofit, repower or retire units from service, all while maintaining system reliability. Although other units were studied, for Yorktown units #1 and #2, the first option was to retrofit the units to meet anticipated environmental rules, but that proved to be the most expensive of the options considered. The second option was to repower the units as oil or natural gas burning facilities, but this option proved to be cost-prohibitive compared to retiring the units and constructing new transmission facilities to address the resulting system impacts. As a third option, the Company evaluated retiring the Yorktown units and constructing a new natural gas generating facility in the North Hampton Roads Load Area, but doing so would require significant upgrades to existing natural gas pipeline capacity, currently insufficient to support such a facility, and could not be completed in time.

As a result of this analysis, the Company determined it would be more cost-effective to address the system impacts resulting from the Yorktown retirements in the North

Hampton Roads Load Area by accelerating the proposed Project than with new generation in this area. The Company also determined that the best option for replacing the retired generation is to build new gas-fired combined-cycle generation located outside the North Hampton Roads Load Area, and it has filed an application with the Commission in Case No. PUE-2012-00128, for such a facility – the proposed Brunswick County combined-cycle project. Ultimately, these IRP analyses demonstrated that neither retrofitted nor repowered generation at Yorktown Units 1 and 2, or new generation in the load area is an economical alternative to the proposed Project for meeting the identified Reliability Violations.

Q. Was additional study conducted by the generation group to develop the 230 kV + Generation Options?

A. Yes, this additional study was conducted by Company Witness Kelly. My understanding is, subject to compliance with codes and standards of conduct, Mr. Nedwick provided Mr. Kelly the requisite amounts of generation at Yorktown in order to allow the different 230 kV Alternatives A, B and C to solve the 2015 and 2021 NERC Reliability Violations. Company Witness Nedwick describes the process he undertook to calculate these levels of generation in his rebuttal testimony and in his Rebuttal Schedule 3. In response, Company Witness Kelly provided the capital costs associated with certain levels of generation at the Yorktown site, subject to several important assumptions that he describes in his rebuttal testimony. The results of Witness Kelly's generation study is presented in his Extraordinarily Sensitive Rebuttal Schedule 3, and summarized in columns D, F and H of my Rebuttal Schedule 1. The "lowest" cost of these 3 alternatives is 230 kV Alternative C + generation, at a cost over three times that of the Project to solve 2015 Reliability Violations and over six times that of the Project to solve 2021 Reliability Violations. In addition, 230 kV Alternative C + generation cannot be constructed until 2021, at the earliest.

Q. Was additional study conducted by the generation group to develop the Stand-Alone Generation Option?

A. Yes, this additional study was also conducted by Company Witness Kelly subject to compliance with codes and standards of conduct and pursuant to the levels of generation determined by Mr. Nedwick in order to allow the 2015 and 2021 NERC Reliability Violations to be solved with generation only. As a result, Mr. Kelly provided the capital costs associated with these levels of generation at the Yorktown site, again subject to several important assumptions that he describes in his rebuttal testimony. Company Witness Kelly provides the results of his additional study in his Extraordinarily Sensitive Rebuttal Schedule 3 (pages 8-9), but the "lowest" cost of Stand-Alone Generation is $633 million in order to provide 620 MW of generation in 2015 and an additional $712 million to provide 620 MW of generation in 2021, for a total of $1,345 million. It is clear that this alternative is not viable because it is cost-prohibitive. In addition, the soonest such a Stand-Alone Generation Option can be constructed is 2016.

Q. Please comment on Staff Witness McCoy's findings.

A. Staff Witness McCoy provided another independent review of the Company's findings. McCoy provides a comprehensive and complete review, in addition to the Company's and that of the Company's routing consultant, Natural Resource Group, LLC ("NRG"), of the entire proposed Project. Staff Witness McCoy recommends on page 34 of the MAE Routing and Environmental Report (Exhibit WDM-1) that the Updated Proposed

Route for the Skiffes Creek 500 kV transmission line, crossing of the James River and Skiffes Creek-Whealton 230kV transmission line should be approved, as well as the proposed siting of the Skiffes Creek 500 kV-230 kV-115 kV Switching Station ("Skiffes Station"). Staff Witness McCoy's findings recognize the industrial nature of the area where the James River Crossing is proposed and its character as a working section of the river. The Company's routing witnesses address Staff Witness McCoy's findings in more detail, but, from my perspective, the Company is encouraged that the Staff's independent review yielded the same conclusion as the Company. The Company's Updated Proposed Route and siting of the Skiffes Station should be approved by the Commission.

Q. Why is it important for the Commission to act on the Company's Application by October 2013?

A. As detailed in my direct testimony, in the direct testimony of Company Witness Nedwick and in the rebuttal testimony of the Company Witnesses Nedwick and Herling, if the Project is not in service by the summer of 2015, numerous transmission lines in the area are projected to overload and/or fall below their minimum voltage requirements under numerous facility loss contingencies, and thereby violate mandatory NERC Reliability Standards. This would place the Company and its customers at risk of cascading outages for a significant portion of its transmission system. Staff Witness Chiles has verified the need. The Additional Analyses continue to support the need in 2015, and the choice of the Project as the best option to solve the need in a robust, reliable and cost-effective manner both in 2015 and for the long-term.

Company Witness Allen addresses the Company's ability to construct the Project by May 31, 2015. The length of time required to construct the overhead 500 kV line proposed in this Project is 15 months and must be completed by December 31, 2014. With a Final Order from this Commission by October 1, 2013, the entire project including the 230 kV line from Skiffes Creek to Whealton is projected to be completed by the May 31, 2015 need date. Receiving Commission approval by October 1, 2013 of the proposed Project is critical to provide the Company with sufficient time to construct and energize the facilities by the summer of 2015.

Q. But Staff Witness McCoy suggests beginning on page 3 of the MAE Environmental Regulations Report (Exhibit WDM-2) that the compliance date for the Mercury and Air Toxics Standards ("MATS") of April 16, 2015 can be subject to extension. Shouldn't the Company seek an extension of the MATS compliance date in order to keep the at-risk generation units running so that it can build one of the 230 kV alternatives?

A. We are presenting the rebuttal testimony of the Company's Chief Environmental Officer, Pamela Faggert, and she does not believe, given that the Company has proposed a solution that can be built by the compliance date, that it can currently make the required showings needed to seek extensions from the state or federal environmental authorities to comply with MATS.

Q. Why does the Company believe it is not required to obtain a special use permit from James City County to construct the proposed Skiffes Station, as JCC Witnesses Middaugh and Reidenbach have suggested?

A. As discussed in greater detail by Company Witnesses Nedwick and Harper, the Company believes that the Skiffes Station is included within the definition of "transmission line" for purposes of preemption from local zoning requirements provided by § 56-46.1 F of the Code of Virginia ("Va. Code"). The Company's Application in this proceeding is not simply for approval of a proposed 500 kV line and 230 kV line, but also for approval of Skiffes Station, without which those proposed lines could not operate and would not be built, as Company Witness Nedwick explains. The switching station is, therefore, inextricably tied to the proposed lines and to the Commission approval the Company is seeking in this proceeding. To allow James City County, or any other local zoning authority, to use this zoning process to block construction of Commission-approved transmission lines by blocking construction of the switching station would be contrary to the Commission's jurisdiction to approve the construction of electric transmission lines under Va. Code §§ 56-265.2 and 56-46.1. Accordingly, the Company is filing in this proceeding, concurrent with its rebuttal testimony, a legal memorandum supporting this position and requesting that the Commission confirm that approval of the Skiffes Station will constitute approval of a "transmission line" for purposes of Va. Code § 56-46.1 F.

Q. Has the Company conducted a rate impact analysis as requested by the Hearing Examiner on January 10, 2013?

A. Yes, we have. The rebuttal testimony of Company Witness Kurt W. Swanson provides the results of a 2015 rate impact analysis comparing the proposed Project with the Updated Proposed Route, the Chickahominy Alternative, and costs of full compliance with NERC Reliability Standards through Alternative B (transmission only)[3]. Alternative

[3]For the sake of illustration, the Company conducted a rate analysis of Alternative B. However, the additional costs to retain Yorktown Units 1 and 2 in order to build Alternative B in 2018 were not included. Alternative A has the same cost as Alternative B. Rate analyses for the three 230 kV + Generation Options or Stand-Alone Generation

B will provide residential rates that are five times higher than the Project, on a total project basis, exclusive of additional costs to retain generation at Yorktown as discussed in footnote 3 herein. If one were to isolate the rate impacts of the Project's 500 kV line alone as compared to Alternative B's double circuit 230 kV facility, Alternative B would have an even greater rate impact because the costs of a 500 kV transmission line are socialized across PJM, while the costs of 230 kV transmission lines are almost entirely borne by the Company's customers. The proposed rate impact, along with Alternative B's inability to solve the 2015 Reliability Violations without additional compliance facilities and its inability to be constructed in time, further show that this alternative is an irresponsible choice for the Company and its customers.

Q. Who are the other Company witnesses filing rebuttal testimony?

A. In response to issues raised by the Respondents, public witnesses, the Hearing Examiner and the Staff, the Company presents the following rebuttal witnesses in support of the proposed Project and Updated Proposed Route.

- Company Witness Nedwick discusses in greater detail why 230 kV alternatives, among others, were rejected by the Company in lieu of the 500 kV Surry-Skiffes Creek line and provides the results of the Additional Analyses required by the Hearing Examiner's January 30 Ruling, which continue to support the Company's choice of the Project to solve the NERC Reliability Violations in 2015.
- Company Witness Steven R. Herling from PJM addresses the reliability analyses that PJM conducted through the RTEP process, including analyses of 230 kV

Option were not conducted because they include generation which adds a level of complexity to the rate analysis because generation costs may be recovered in base rates or through a rate adjustment clause. Rate analysis was not conducted for Alternative C because it is not able to be constructed.

alternatives and non-incumbent transmission developer alternatives (LS Power Proposal) to the Project, the effect of demand response and energy efficiency on the need for the Project, and whether new, retrofit or repowered generation should be relied upon to solve the reliability need.

- Company Witness Allen presents evidence regarding the feasibility, cost and inadvisability of constructing Alternatives A, B and C and the construction time estimates for all the transmission alternatives.
- Company Witness Thomasson provides underground construction cost estimates for Alternatives A and B.
- Company Witness Faggert provides the effective and anticipated environmental regulations affecting the Company's at-risk generation units and the Company's view of its ability to qualify for an extension of the MATS from state or federal environmental regulatory authorities. She also addresses environmental limitations on the operation of Yorktown Unit 3.
- Company Witness Kelly provides the results of the retrofit, repower, retirement analysis that was conducted for at-risk generating units during the 2011 and 2012 IRP cycles, as well as the results of the generation portion of the 230 kV + Generation Options and Stand-Alone Generation Option required by the January 30 Ruling.
- Company Witness Swanson provides the estimated customer impacts of the proposed Project with the Updated Proposed Route, the Chickahominy Alternative, and costs of full compliance with 2015 NERC Reliability Standards through Alternative B (transmission only).

- Company Witness Harper addresses the process that led to the selection of the proposed Project with the Updated Proposed Route, the Company's comments on the DEQ Report, the viewshed impact of the Updated Proposed Route, the difficulties in routing an underground line using either the James River Crossing Variation 1 or Variation 3 route, the inability to construct Alternative C in time to meet the need, and the impacts on BASF property.
- Company Witness Edward Twiss of TrueScape Limited addresses comments regarding visual simulations prepared as part of the Company's Environmental Routing Study and provides a revised visual simulation from the Carter's Grove viewpoint.
- Company Witness Douglas J. Lake of NRG, addresses the routing process, the developed landscape of the Updated Proposed Route, and the anticipated impacts to the BASF property and Carter's Grove.
- Dr. Marvin L. Wolverton addresses comments regarding diminution of property values proximate to the proposed Project and impacts to the local area's visitor experience.
- Company Witness Cathy Taylor addresses the environmental remediation occurring on the BASF property and statements made by BASF Witness Vernon Burrows.
- Company Witness Michael Brucato addresses the Company's right-of-way clearing practices and responds to specific requests relating to right-of-way clearing made by BASF Witness Burrows.
- Company Witness Dr. Linda S. Erdreich addresses comments by Witness

David O. Ledbetter regarding the issue of EMF and its effects on human health, if any, related to the Project.

Q. Do you have any concluding remarks?

A. Yes. The Staff's independent need consultant verified the need for the Project and that the Project reliably, responsibly and reasonably addresses this need. The Staff's independent routing consultant has recommended that the Updated Proposed Route and the site for the Skiffes Station be approved. The Additional Analyses continue to show that the Surry-Skiffes Creek overhead 500 kV line is the best, most cost-effective, viable solution for meeting the needs of the North Hampton Roads Load Area now, as well as providing for a robust and reliable system capable of meeting the needs of that area in the future, in a safe, responsible and economical manner. For these reasons, and those set forth in the testimony of the direct and rebuttal witnesses, the Project should be approved by no later than October 1, 2013 by the Commission.

Q. Mr. Hathaway, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

Company Exhibit No. __
Witness: SCH
Rebuttal Schedule 1
Page 1 of 1

Additional Analyses Summary Results

		A	B	C	D	E	F	G	H	I
				Alternative A[1] - 230kV		Alternative B[2] - 230kV		Alternative C[3] - 230kV		
		Proposed Project including 500 kV Updated Proposed Route	Overhead 500 kV Chickahominy Alternative	Transmission Only	Transmission Plus *Generation* [9]	Transmission Only	Transmission Plus *Generation* [9]	Transmission Only	Transmission Plus *Generation* [9]	Stand Alone *Generation* Option[4,9]
1	Does project electrically address 2015 NERC Reliability Violations?	YES	YES	NO	YES[5]	NO	YES[5]	NO	YES[5]	YES[5]
2	COST	$155.4 M	$213.2 M	$273.8 M	$623.8 M	$440.4 M	$540.4 M	$144.8 M	$494.8 M	$633.0 M
3	If "NO" in Line 1, what is the cost of additional transmission facilities to fully resolve 2015 NERC Reliability Violations?	Ø	Ø	$214.8 M	Ø	$48.2 M	Ø	$ 82.1 M	Ø	Ø
4	Total COST to fully resolve 2015 NERC Reliability Violations	$155.4 M	$213.2 M	$488.6 M	$623.8 M	$488.6 M	$540.4 M	$ 226.9 M	$494.8 M	$633.0 M
5	Can construction necessary to fully resolve 2015 NERC Reliability Violations be completed by June 1, 2015?[6]	YES	YES	NO	NO	NO	NO	NO	NO	NO
6	Can construction necessary to fully resolve 2015 NERC Reliability Violations be completed by April 16, 2017?[7]	YES	YES	NO	YES	NO	NO	NO[8]	NO	YES
7	Additional COST to fully resolve 2021 NERC Reliability Violations	$17.3 M	$17.3 M	$26.7 M	$577.0 M	$26.7 M	$577.0 M	$181.9 M	$577.0 M	$712.0 M
8	Total COST to fully resolve 2021 NERC Reliability Violations	**$172.7 M**	**$230.5 M**	**$515.3 M**	**$1,200.8 M**	**$515.3 M**	**$1,117.4 M**	**$ 408.8 M**	**$1071.8 M**	**$1,345.0 M**
9	Completion date for facilities to address 2015 NERC Reliability Violations	2015	2015	2018	2017	2018	2018	N/A[8]	2021	2016

Notes:

1 Alt. A: underground 230 kV hybrid single circuit (1000 MVA) on James River Crossing Variation 3 Hybrid Conceptual Route.
2 Alt. B: underground 230 kV hybrid double circuit (1000 MVA/circuit) on James River Crossing Variation 3 Hybrid Conceptual Route.
3 Alt. C: rebuild of the existing James River crossing of 230 kV Line #214 and 230 kV Line #263.
4 Amount of generation at Yorktown that is the "lowest" cost to solve the need. 620 MW in 2015 and 2021 (2 units minimum; lose 1 unit and maintain ≥ 295 MW).
5 Electrically resolves NERC Reliability Violations assuming generation at Yorktown is retained and/or added until violations are resolved.
6 Date by which the 2015 NERC Reliability Violations must be resolved.
7 If requested and granted, date by which fourth and fifth year MATS extensions end.
8 Alternative C is NOT constructible without generation already in place to address reliability issues that result from the wreck and rebuild of existing lines.
- Generation required to be in place to support construction would cost between $383M - $652M.
- To construct the facilities needed to address NERC Reliability Violations in 2015 would take 10 years. Additional construction time would be needed to address 2021 NERC Reliability Violations.
9 Retrofit and repower options require 3-years of capital expenditures for construction and implementation (excluding permitting), beginning July 1, 2013. Effect of multiple retrofit and repower options being executed at the same time has not been incorporated.

Nedwick

REBUTTAL TESTIMONY
OF
PETER NEDWICK
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. I am Peter Nedwick, and I am a Consulting Engineer in Electric Transmission Planning for Dominion Virginia Power. My office is located at 701 East Cary Street, Richmond, Virginia.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, my prefiled direct testimony on behalf of Dominion Virginia Power was submitted to the State Corporation Commission of Virginia (the "Commission") in this matter on June 11, 2012.

Q. What is the purpose of you rebuttal testimony?

A. I will respond to the prefiled testimony of Staff Witness John Chiles of GDS Associates, Inc. ("GDS"), who provided an independent analysis of the need for the Company's proposed Project and who also provided analysis of a set of four 230 kV transmission alternatives (two overhead and two hybrid with underwater crossings of the James River) to the Company's proposed 500 kV Surry-Skiffes Creek overhead transmission line, as well as generation alternatives. I will provide and comment on the results of a series of updated flow studies directed by the Hearing Examiner as to the proposed Project, two underground 230 kV alternative lines to Skiffes Creek Switching Station ("Skiffes

Station"), one overhead 230 kV alternative at another location, and two generation driven alternatives. I also will respond to the testimony of James City County (or "JCC") Witnesses Waine P. Whittier and Robert Middaugh, who support consideration of a 230 kV hybrid to Skiffes Station (with underwater crossing of the James River) or a rebuild of the Company's two existing 230 kV circuits that cross the James River at Newport News, as alternatives to the Company's proposed 500 kV overhead line. Finally, in response to the testimony of JCC Witnesses Middaugh and Tamara Rosario (as adopted by JCC Witness Leanne Reidenbach), who assert that the Company needs to obtain a special use permit ("SUP") from James City County in order to build the Skiffes Station, I will explain why the Commission should find that the proposed Skiffes Station is a "transmission line" for the purposes of Va. Code § 56-46.1 F.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, PN, consisting of Rebuttal Schedules 1-13, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. The additional analyses ("Additional Analyses") conducted pursuant to the Hearing Examiner's January 30, 2013 Ruling ("January 30 Ruling"), based on the 2013 Load Forecast and updated assumptions requested by the Hearing Examiner, clearly continue to demonstrate that the proposed Project continues to resolve all identified violations of mandatory North American Reliability Corporation ("NERC") Reliability Standards ("NERC Reliability Violations" or "Reliability Violations") in 2015, can be constructed in time to meet a projected June 2015 in-service date and is by far the most economical solution. The Company's proposed 500 kV Chickahominy Alternative continues to be the next most viable alternative. As discussed in greater detail in my rebuttal testimony, this is the same conclusion that has been reached by five different reliability analyses of the same Reliability Violations conducted over the last few years.

My rebuttal testimony is organized as follows:

I. BACKGROUND

Q. Please provide the context for Mr. Chiles's testimony.

A. Mr. Chiles was engaged by the Commission Staff to provide an independent analysis of the Company's Application as it relates to need for the proposed Project. As was explained in the Appendix and my direct testimony, the Company's power flow studies, conducted as part of the development with PJM Interconnection, LLC, ("PJM") of PJM's Regional Transmission Expansion Planning Process ("RTEPP"), show that the Company's transmission system will not be able to maintain compliance with mandatory NERC Reliability Standards in the generation-deficient North Hampton Roads Load Area (the Peninsula, Middle Peninsula and Northern Neck) by Summer (commencing June 1) of 2015. Specifically, these studies showed multiple NERC Reliability Violations for

NERC Categories B (single-contingency), C (multiple contingency) and D (right-of-way). Based on power flow studies conducted in the first quarter of 2011 and utilizing the 2010 PJM Load Forecast, these NERC Reliability Violations were projected to begin to occur by Summer of 2019. In November of 2011, however, the Company announced it would retire by the end of 2014 three coal-fired generating units at its Yorktown Power Station ("Yorktown") (Unit 1) and Chesapeake Energy Center ("CEC") (Units 1 and 2), totaling 381 MW, in order to achieve cost-effective compliance with effective and anticipated environmental regulations. As noted on pages 72 and 78-81 of the Appendix, studies done in the first quarter of 2012 and using the 2011 PJM Load Forecast showed that these retirements had the effect of accelerating the NERC Reliability Violations from 2019 to 2015. Specifically, the retirement at Yorktown Unit 1 drove acceleration to 2015, of the need for the proposed Project.[1] The retirement of Yorktown Unit 2 in 2015, which was announced in September of 2012 as part of the Virginia/North Carolina 2012 Integrated Resource Plan, only further increase the severity of the NERC Reliability Violations in 2015. Those findings were confirmed by additional studies using the 2012 PJM Load Forecast that were performed in preparation for filing the Company's Application in this proceeding. The retirements at CEC are the drivers accelerating the need for certain other projects outside the North Hampton Roads Load Area to 2016.

The Company determined that a new 500 kV source into the North Hampton Roads Load Area at Skiffes Station is required to resolve the identified short-term and long-term NERC Reliability Violations and developed two feasible 500 kV sources from which a new 500 kV source could emanate. The Company developed the proposed Project to

[1] Either retirement of Yorktown Unit 1 or Unit 2 would accelerate the need for the Project to 2015. Once the Project is completed in 2015, Yorktown Units 1 and 2 are not needed for reliability.

provide that 500 kV source from Surry Switching Station ("Surry Station") to support the 230 kV system by extending a new 230 kV line from Skiffes Station down the Peninsula to Whealton Substation in the City of Hampton. The Company also proposed an alternative 500 kV source to Skiffes Station from Chickahominy Substation. Both 500 kV sources are electrically viable and functionally equivalent.

Q. Were Mr. Chiles and GDS able to verify the results of the Company's Power Flow Studies?

A. Yes, as noted on pages 16 and 31 of Mr. Chiles's Direct Testimony and also on page 6 of Mr. Chiles's Attachment JWC-2, GDS was able to verify the results of the Company's Power Flow Studies.

Q. Was GDS able to make a determination as to need for the Project?

A. Yes, Mr. Chiles noted on page 31 of his testimony and on page 15 of Exhibit JWC-2 that the Project adequately addresses the identified NERC Reliability Violations.

II. A 500 KV SOLUTION IS REQUIRED

Q. Did the Company propose a 230 kV alternative to the 500 kV Surry-Skiffes Creek line?

A. No. As explained in the Appendix and my direct testimony, no 230 kV solution, whether single circuit or double circuit, and whether underground, overhead, or hybrid, resolves all of the identified NERC Reliability Violations. Only a 500 kV solution does that.

Moreover, attempting to address NERC Reliability Violations on the 230 kV system in North Hampton Roads by creating another 230 kV connection into that area from South Hampton Roads (e.g., Surry Power Station), as would be the case with 230 kV

Alternatives A, B and C discussed in detail below, would merely increase the supply requirements in South Hampton Roads, which is also generation deficient.

A new 230 kV connection across the James River would merely permit more power to flow from one generation-deficient portion of the 230 kV system (South Hampton Roads) to another (North Hampton Roads). It would not solve the significant lack of bulk capacity that is needed to increase the ability of each 230 kV system to serve local load, which can only be provided by an extension of the 500 kV system into the area.

The 500 kV system is the major source of bulk power to the Company's customers. Its primary purpose is to support the reliable and safe transmission of bulk capacity and associated energy from remote generation sources to major load centers. At these major load centers, bulk power is transformed to flow from the 500 kV system to the 230 kV system to satisfy the area's capacity and energy requirements. In the South Hampton Roads Load Area, these major 500 kV to 230 kV transformations are achieved at Fentress Station, Suffolk Station, and Yadkin Station. In 2011 (pre-generation retirement), the Company built an approximately 60-mile long 500 kV line from Carson Station to Suffolk Station to support continued reliable service to the customers located in the South Hampton Roads Load Area. However, there is currently no such 500 kV source of bulk power into the North Hampton Roads Load Area.

My Rebuttal Schedule 1 shows the bulk power requirements for North and South Hampton Roads for Summer 2015 and Summer 2021 under both normal conditions and critical system conditions ("CSCs") based on the 2013 PJM Load Forecast. This schedule, including the table on page 5, demonstrates that in 2015, under normal operating conditions, North Hampton Roads Load Area will import 86.6% of its capacity from west of Richmond, while South Hampton Roads will import 52%. Under CSCs, the import requirements for North Hampton Roads increase to 99% and for South Hampton Roads to 75%. By Summer 2021, North Hampton Roads must import 87% of its capacity from west of Richmond under normal operating conditions, and 98% under CSCs, while these figures for South Hampton Roads increase to 54.6% and 76.6%, respectively. Simply increasing the capacity of existing 230 kV tie lines between two generation deficient areas or by adding an additional new 230 kV circuit between them cannot meet the need for a *new* source of bulk capacity and energy into the area most immediately in need, the North Hampton Roads Load Area.

Q. Did the Company include information regarding 230 kV alternatives in its filing?

A. Yes. Because 500 kV underground construction is not viable, we were aware that potential opponents of the proposed Surry-Skiffes Creek line might seek to have that line installed underground at 230 kV, in whole or in part, so we thought it would be helpful to provide an estimate of what that would cost. Accordingly, we provided in Section I.C of the Appendix our estimated costs for a 230 kV double circuit line from Surry Station to Skiffes Station, with either hybrid underground/overhead or all-underground installation. In addition, a 230 kV Surry-Skiffes Creek single circuit hybrid line with an underwater crossing of the James River had been proposed to PJM by a non-incumbent transmission developer subsidiary of LS Power. We also provided in Appendix Section I.C materials developed by PJM describing its analysis and rejection of the LS Power proposals, which included the developer's estimated cost of that project.

Q. Was GDS able to determine if any 230 kV alternatives were satisfactory compared to the proposed 500 kV Surry-Skiffes Creek line?

A. Yes, they were able to determine that none of the four 230 kV alternatives that they studied (single circuit hybrid underground crossing, a double circuit hybrid underground crossing, single circuit overhead crossing and a double circuit overhead crossing) resolved all the identified Reliability Violations. Furthermore on page 32 of Mr. Chiles's testimony he states:

> I do not recommend the construction of a double circuit 230 kV overhead Surry-Skiffes Creek transmission line, as it is less effective than the Project. Further, I do not recommend the construction of a 230 kV Surry-Skiffes Creek hybrid line (either single or double-circuit) due to identified reliability issues and expected cost increase and practicality to build.

III. ADDITIONAL ANALYSES

Q. How will the Company approach discussion of 230 kV alternatives in its rebuttal testimony?

A. During the public hearing held in this proceeding on January 10, 2013, the Hearing Examiner directed the Company to investigate whether a hybrid line would be feasible. This hypothetical hybrid line, at either single or double circuit 230 kV would run overhead from Surry Station to an overhead-to-underground transition station at the shore of the James River in Surry County, then cross the James River underwater and, upon coming ashore on the BASF property along the James River Variation 3 route, continue underground along that route until reaching an underground-to-overhead transition station at the intersection of the James River Crossing Variation 3 route and BASF Drive, from which the line would continue overhead north with the Proposed Route along BASF Drive and across U.S. Route 60 to Skiffes Station. On page 2 of his January 30 Ruling, the Hearing Examiner stated that "in order to verify the load flow modeling, contingency analyses, and reliability needs Dominion Virginia Power presented to justify the proposed new line, updates to the load flow analyses should be performed as proposed" by the Company and the Staff, with two modifications, all of which are provided in the matrix of these load flow cases and studies, as modified and directed by the Hearing Examiner (the "Studies Matrix"), contained in my Rebuttal Schedule 2.

In addition to updated power flow studies of the Company's proposed Project, the Hearing Examiner also directed the Company to study three 230 kV alternatives to the proposed Surry-Skiffes Creek 500 kV line. Alternatives A and B are the single and double circuit versions of the Hearing Examiner's Variation 3 Hybrid, based on a cable configuration providing transfer capability of 1000 MVA per circuit. Alternative C is a conceptual rebuild and reconfiguration of the existing approximately 4.5-mile crossing of the James River from Isle of Wight County to the City of Newport News by the Company's 230 kV Surry-Winchester Line #214 and 230 kV Chuckatuck-Newport News Line #263 ("Newport News Crossing"), discussed in the testimony of JCC Witness Whittier as I have mentioned. Based on these directions by the Hearing Examiner, the Company's analysis of 230 kV alternatives will focus on the cost and reliability performance of the Alternatives A, B and C. The cost and reliability performance of these 230 kV alternatives are necessarily combined because none of them will resolve the identified NERC Reliability Violations in 2015 without the construction of additional facilities, so the cost of each alternative includes the cost of those additional facilities required to achieve full compliance with NERC Reliability Standards. The cost to achieve full compliance in 2021 also must be included, as explained below.

Q. Please describe the studies you were directed to perform.

A. The specific studies we were directed to perform are listed in the matrix of studies provide as my Rebuttal Schedule 2. For the basecase, we were directed to utilize the 2013 PJM Load Forecast and to include all announced generation retirements at Yorktown and CEC and the addition of certain transmission "Pre-Projects" approved by PJM. We also were directed to assume Yorktown Unit 3 was off-line for all studies.

For the proposed Project we were directed to study its performance in 2015 and 2021 in resolving NERC Reliability Violations with and without the CSC of Surry 500 kV Unit 2 being off-line (Matrix Studies 1-4 and 8-11). Also for the proposed Project we were directed to study its performance in complying with NERC Reliability Standards in 2021, assuming none of the scheduled retirements at Yorktown and CEC and with and without Surry Unit 2 off-line (Matrix Studies 23-26).

Each 230 kV alternative was to be analyzed to determine, for 2015 and 2021 with and without the CSC of 230 kV Surry Unit 1 off-line, whether the alternative can resolve all of the identified NERC Reliability Violations and, if not, to determine what additional transmission facilities would be required to comply with NERC Reliability Standards (Matrix Studies 5-7 and 12-14) and what combination of each 230 kV transmission alternative with a generation solution (retrofit, repower or new) could resolve the identified NERC Reliability Violations (Matrix Studies 15-22). As directed, an assumed 800 MW block of generation at the Yorktown 230 kV bus was the starting point for evaluation of these combined transmission/generation 230 kV alternatives. I prepared a description of how I created the generation study results, which is attached as my Rebuttal Schedule 3. The generation study results are shown in Table 1 below.

Table 1

	Alternative A	Alternative B	Alternative C	Stand-Alone Option
2015				
MW Required	1008	159	522	620
MW Size of smallest unit	0	0	56	295
2021				
MW Required	1449	551	505	620
MW Size of smallest unit	87	27	139	295

These generation requirements were given to Company Witness Glenn A. Kelly, subject to compliance with state and federal codes and standards of conduct, to analyze the generation costs related to the above-levels of generation at Yorktown. We also asked him to study the theoretical amount of stand-alone generation at Yorktown that would resolve all NERC Reliability Violations (Matrix Studies 15-16 and 19-20).

The applicable NERC Reliability Standards and categories are described in detail in the Company's Appendix at pages 17-18.

Q. How did the PJM 2013 Load Forecast impact the Dominion Virginia Power System Load?

A. The new 2013 Load Forecast is projecting a 2015 Summer Peak load of 20,747 MW and Summer 2021 Summer Peak of 22,931 MW, which is 417 MW and 308 MW lower than the PJM 2012 Load Forecast. This equates to a projected load based on the 2013 Load Forecast in the North Hampton Roads Load Area of 2,097 MW in 2015 and 2,268 MW in

2021, which is 42 MW and 40 MW, respectively, lower than the 2012 Load Forecast. These new 2013 Load Forecast values were incorporated into the 2015 and 2021 Power Flow models, which are based on the 2012 Load Forecast, by reducing the entire Dominion Virginia Power System loads down by the 417 MW and 308 MW, respectively, in 2015 and 2021. The new 2013 Load Forecast also includes new energy efficiency and demand-side management values, which are incorporated into reliability assessments as required by the reliability assessment being conducted. The 2015 and 2021 Power Flow models were then updated to reflect any additional system changes that have occurred over the last six months.

Q. Please summarize the results of these updated studies.

A. The 2015 studies show that the Company's proposed Project resolves all identified NERC Reliability Violations, but none of the 230 kV Alternatives A, B or C is able to resolve all Reliability Violations in 2015 without constructing additional transmission and/or generation facilities. There also would be additional fuel expense, but that was not specifically quantified for purposes of the Additional Analyses.

The studies show further that the proposed Project is still needed in 2021, with the addition of a minor upgrade of a 115kV line in the area (a variation of which shows up in all the alternatives in that timeframe), and continues to resolve the identified NERC Reliability Violations. All of the 230 kV, 230 kV + generation and stand-alone generation options would require much more extensive and costly facilities to achieve the same results and could not be achieved by the 2015 need date. More detail on these results is provided in my Rebuttal Schedule 4. The actual print outs of the results are contained in Volumes III through VI of this rebuttal testimony and correspond to the

Additional Analyses designations set forth in my Rebuttal Schedule 4.

Q. What are the costs of these alternatives?

A. A detailed comparison of the costs of the proposed Project and alternatives is provided in my Rebuttal Schedule 5. The costs of the alternatives are not useful because, as I will explain in more detail, none of them could be constructed by the need date. The costs to construct 230 kV hybrid underground Alternatives A and B, and the cost of the 230 kV overhead Alternative C Newport News Crossing rebuild, are provided in the rebuttal testimony of Company Witnesses Walter R. "Trey" Thomasson, III and Mark S. Allen. The additional transmission facilities that would be required to bring Alternatives A, B and C into full compliance with NERC Reliability Standards are described on pages 11, 12 and 13 of my Rebuttal Schedule 4. The costs to construct the additional overhead transmission facilities that would be required for Alternatives A and B to be in full compliance with NERC Reliability Standards, as well as the cost of the Alternative C overhead facilities required for the rebuild of the existing James River crossing circuits, are provided in Rebuttal Schedule 4 to the rebuttal testimony of Company Witness Mark Allen. The costs of additional generation required to meet NERC Reliability Standards are provided in the rebuttal testimony of Company Witness Glenn Kelly. These combined results are summarized in Table 2 below subject to the same comments regarding constructability, timing and generation availability and costs as set forth on my Rebuttal Schedule 5.

Table 2

Alternative	2015 Total Cost	2015 Excess Over Proposed Project	2021 Total Cost	2021 Excess Over Proposed Project
Surry 500 kV (Proposed Project with Updated Proposed Route)	$155.4 M	$0.0	$172.7 M	$0.0
Chickahominy Alternative 500 kV	$213.2 M	$57.8 M	$230.5 M	$57.8 M
Surry 230 kV Alternative A	$488.6 M	$333.2 M	$515.3 M	$342.6 M
Surry 230 kV Alternative B	$488.6 M	$333.2 M	$515.3 M	$342.6 M
230 kV Alternative C	$226.9 M	$71.5 M	$408.8 M	$236.1 M
230 kV Alt A + Generation	$623.8 M	$468.4 M	$1,200.8 M	$1,028.1 M
230 kV Alt B + Generation	$540.4 M	$385.0 M	$1,117.4 M	$944.7 M
230 kV Alt C + Generation	$494.8 M	$339.4 M	$1,071.8 M	$899.1 M
Yorktown Stand-Alone Generation	$633.0 M	$477.6 M	$1,345.0 M	$1,172.3 M

Clearly, the proposed Project remains the most timely, robust and economical solution to the identified reliability violations.

Q. Why have these 230 kV alternatives been put forward?

A. James City County and a number of other Respondents have stated their opposition to any overhead crossing of the James River to Skiffes Station and no one in the case supports an overhead 230 kV line to Skiffes Station. So, when these opponents propose the use of a 230 kV line from Surry Station to Skiffes Station they do so because they want at least the James River crossing portion of such a line to be constructed underground. This means that, because using 230 kV would not address all of the identified NERC Reliability Violations in 2015, as verified by the Company in the Appendix, Staff Witness Chiles and, again, by the Company through the Additional

Analyses, the project cost of a 230 kV version of a Surry-Skiffes Creek line would include, in addition to the much higher cost of underground construction, the cost to complete the job by making additional transmission upgrades to resolve all of the NERC Reliability Violations that 230 kV cannot solve (i.e., the additional cost for full compliance facilities). This ensures an appropriate apple-to-apples comparison of costs for purposes of Commission consideration and decision-making. For example, using the Company's estimated cost to construct the 230 kV Alternative B, which will not solve the identified NERC Reliability Violations in 2015, the preliminary cost for partial compliance to construct Alternative B would be $440.4 million (provided by Company Witness Thomasson) plus the $48.2 million cost of the additional transmission upgrades required to fully comply with NERC Reliability Standards (provided by Company Witness Allen), for a total cost of $488.6 million.

The necessary inclusion of the cost of additional transmission facilities required to fix NERC Reliability Violations not addressed by the use of inadequate 230 kV facilities, and associated costs to ratepayers, is presented in greater detail in my Rebuttal Schedule 5 for each of the alternatives we were directed to study. This much greater cost, and the associated reliability and operating risks of underground construction described by Company Witness Mark Allen in his rebuttal testimony, would be incurred by all of the Company's customers in order to avoid any additional visual impacts above those that already exist from the James City County side of an overhead transmission line river crossing to Skiffes Station, as described by Company Witnesses Doug Lake and Liz Harper in more detail in their rebuttal testimonies.

Q. Does James City County indicate who would be responsible for these additional costs?

A. No, they do not.

Q. Could the use of either 230 kV and/or underground construction have an adverse impact on the Company's customers as a result of cost allocation at the federal level?

A. Yes. As the Company explained in its response to Question No. 23 of the Staff's Second Set of Interrogatories, a copy of which is attached as my Rebuttal Schedule 6, under the currently effective cost allocation methodology approved by FERC, 12.28% of the cost of a 500 kV line is allocated to the Company's customers, while 99.84% of the cost of a new 230 kV line is allocated to the Company's customers. The effect of this difference in PJM allocation methodologies is seen in Company Witness Kurt Swanson's rebuttal testimony, which demonstrates that approximately five times as much cost is allocated to the Company's customers for 230 kV facilities as for 500 kV facilities. I should also mention that Old Dominion Electric Cooperative and other wholesale customers of the Company have taken the position in recent litigation at FERC that the cost of any transmission line installed underground for local aesthetic reasons should be allocated 100% to the Company's retail customers.

Q. Did the Hearing Examiner direct the Company to examine the difference between using High Pressure Fluid Filled ("HPFF") Cable or cross-linked polyethylene ("XLPE") Cable for the 230 kV underground construction proposed for Alternative A and B?

A. Yes, and I will discuss the differences in the applications in the power flow models and in voltage control requirements. Company Witness Thomasson will discuss the engineering and construction difference between these two technologies. As I indicated at the pre-hearing conference held on January 30, 2013 in Richmond, the major difference between these two cable types is the charging current associated with them that will impact the voltage control requirements. The parameters for the two technologies are shown below.

230 kV Hybrid Options per circuit:

HPFF Cable:

Z1= 0.0001456 + j0.0006741 pu Charging MVAr = 170.9MVAr

XLPE:

Z1 = 0.000461 + j0.000858 pu Charging MVAr = 109.1 MVAr

As can be seen from reviewing the two line impedances, the major difference between the two options is approximately 62 MVAr of charging current per circuit. This difference would impact the number of 230 kV reactor banks that would need to be installed to help deal with the voltage effects of the underground circuits. The Company has needed to install 100 MVAr 230 kV Reactor banks system wide to help maintain voltages within acceptable limits especially during light loading conditions; this has been especially true with recent 230 kV underground installations like Garrisonville and Hamilton. The proposed Alternative A using HPFF Cable will require three 230 kV reactor banks (two at Surry Station and one at Skiffes Station) to deal with the capacitive effects of these cables, as noted in the rebuttal testimony of Company Witness Thomasson. If XLPE was used, then only two reactor banks would need to be installed initially. While there will still be some slight power flow differences between the two applications, since there is a difference in the impedances, it is not significant enough to change study results

Therefore, when looking in the change of project scope between an XLPE or HPFF Cable application, the decrease in number of 230 kV reactor banks from three to two would save $6 million if XLPE were used over HPFF Cables.

Q. What response do you have, from a transmission planning standpoint, to the conceptual approach of the recent studies of the 230 kV alternatives?

A. The goal of our transmission planning effort, and that of PJM, is to determine the most cost-effective transmission solution that will best resolve identified NERC Reliability Violations. This goal is contrary to an approach that would reject a transmission solution that resolves all of the identified violations and can be built by the need date and, instead, consider a project to build a more expensive 230 kV solution that would not resolve all NERC Reliability Violations, would require the building of additional 230 kV transmission upgrades and/or generation additions until all violations can be resolved, would require generation to continue to run in a cost-ineffective manner, and that cannot meet the need date. Approval of such an approach would represent a significant departure from how the Company and the Commission have approached transmission planning to date.

As Company Witness Steven Herling of PJM explains in his rebuttal testimony, PJM's FERC-approved protocol for development of its annual Regional Transmission Expansion Plan ("RTEP") is focused on planning and construction of transmission solutions to resolve NERC Reliability Violations. Appropriate consideration is given to market-based non-transmission alternatives, including the effects of demand-side management and proposed generation facilities that have progressed to the point where it is appropriate to include them in transmission planning models. However, PJM cannot approach resolution of NERC Reliability Violations by assuming that generation not in the queue could be used to resolve such violations not resolved by a given transmission project. The Company's transmission line applications to this Commission include analysis of the potential for generation to obviate the need for proposed transmission facilities, and the Company's Integrated Resource Planning process considers the most up-to-date transmission system topology and available capacity of the transmission system in assessing the need for new generation resources. An approach to transmission planning that would rely on developing a solution that would *not* resolve all of the identified NERC Reliability Violations unless additional system improvements were added would constitute a significant and unwarranted departure from the transmission planning and approval processes used by the Company and this Commission. In addition, this approach is inconsistent with the PJM RTEP protocol.

Finally, as alluded to earlier, even if they were electrically sufficient or cost-effective, none of the 230 kV transmission alternatives, the 230 kV + generation or the Stand-Alone Generation Option could be built in time to meet the need date of June 1, 2015. Company Witness Mark Allen's prefiled rebuttal testimony states that either of 230 kV underground Alternatives A or B would require a minimum construction time of five years to be fully NERC-compliant for 2015, meaning neither alternative would be available until June of 2018, three years after the NERC Reliability Violations must be addressed. As Company Witness Liz Harper states in her rebuttal testimony, at least one component of Alternative C – construction of a new river crossing for Line #214 – and perhaps others, would require an application to the Commission (including notice to the affected localities, affected landowners and the public and a routing analysis of environmental impacts) for amendment of the existing certificate of public convenience and necessity authorizing installation of that circuit on the existing double circuit structures. Moreover, Company Witness Mark Allen's rebuttal testimony states that at least ten years would be required to build Alternative C and the additional facilities required to bring Alternative C into compliance with NERC Reliability Violations in 2015, and our reliability analysis shows that the outages required for that construction can only be obtained if both Yorktown Units 1 and 2 continue in operation for those 10 years. Obviously, Alternative C is not a viable solution when those units will be retired by June of 2015. Since it takes ten years to construct Alternative C and the additional compliance facilities to address the 2015 NERC Reliability Violations, Mr. Allen did not address the additional time it would take to build the facilities needed to address the 2021 Reliability Violations caused by Alternative C.

Q. As to the Company's proposed Project, are the basic conclusions of these studies different from those of previous reliability studies?

A. No, they are not. Before these new studies were done, four separate reliability analyses had identified the need for the Project. My Rebuttal Schedule 7 provides a timeline of the various reliability analyses that have been completed over the last two years to verify the need for the proposed Project, including the 500 kV Surry-Skiffes Creek line.

1. In the first quarter of 2011, the Company verified the need for the

proposed Project as part of its routine reliability analysis (2011 Reliability Analysis). The main function of this reliability analysis was to determine what existing and new projects should be incorporated or maintained in the Company's Long Term Transmission Plan to comply with NERC Reliability Standards. This analysis reflected the following:

A. Summer 2019 and Summer 2020 power flow models;

B. 2010 and 2011 PJM Load Forecast(s), respectively; and,

C. No retirements of Yorktown Unit 1 and CEC Units 1 and 2 by 2015, and CEC Units 3 and 4 by 2016, which were not announced until November of 2011.

The 2011 Reliability Analysis confirmed the continued need for the proposed Project and showed a projected need date of Summer 2019.

2. The PJM Reliability Analysis was conducted between December 2011 and April 2012 by PJM ("PJM Analysis"). The driver for the PJM Analysis was the retirement letters sent to PJM in November of 2011 announcing the retirement schedule for Yorktown Unit 1and CEC Units 1 through 4. This PJM Analysis reflected the following:

A. Summer 2015 and Summer 2016 Power Flow Cases;

B. 2011 PJM Load Forecast; and

C. The Company's September 2011 announcements that Yorktown Unit 1 and CEC Units 1 and 2 will be retired by 2015, and CEC Units 3 and 4 will be retired by 2016.

The PJM Analysis identified multiple NERC Reliability Violations throughout the Company's transmission system, including the North Hampton Roads Load Area, and the proposed Project was one of several Company projects selected by PJM to resolve these NERC Reliability Violations. The required need date for this Project was June 2015. Competing proposals by LS Power were rejected by PJM.

3. The third reliability analysis was conducted by the Company between April 2012 and June 2012 by the Company for inclusion in its Application filed with the Commission in June of 2012 in this proceeding ("Company 2012 Analysis"). This reliability analysis reflected the following:

A. The Summer 2015, Summer 2016 and Summer 2021 power flow cases, which were updated to reflect the transmission system topology in the Project area;

B. The 2012 PJM Load Forecast;

C. The Company's November 2011 announcements that Yorktown Unit 1 and CEC Units 1 and 2 will be retired by 2015, and CEC Units 3 and 4 will be retired by 2016; and

D. Retirement of Yorktown Unit 2 by 2015 as CSC.

The results of the Company 2012 Analysis continued to demonstrate NERC Reliability Violations in the North Hampton Roads Load Area and that the proposed Project resolves these reliability deficiencies. GDS confirmed these same conclusions in their report filed with the Commission in January of 2013.

4. The fourth reliability analysis was conducted by GDS and filed January 11, 2013 to verify the Company's power flow studies ("GDS 2013 Analysis"). This analysis reflected the following:

A. Summer 2019 and Summer 2020 power flow models from the 2011 Reliability Analysis, which were based on:

1. 2010 and 2011 PJM Load Forecast(s), respectively,

2. No retirements of Yorktown Unit 1 and CEC Units 1-4; and

B. Summer 2015, Summer 2016 and Summer 2021 power flow cases, which were updated to reflect the transmission topology in the Project area and were based on:

1. 2012 PJM Load Forecast; and

2. The Company's September 2011 announcements that Yorktown Unit 1 and CEC Units 1 and 2 will be retired by 2015, and CEC Units 3 and 4 will be retired by 2016.

In summary, four separate, prior reliability studies conducted by the Company, by PJM, and by GDS, confirmed the reliability need for the proposed Project by 2015 and that the proposed Project resolves these deficiencies and achieves full compliance with NERC Reliability Standards.

IV. STAFF WITNESS CHILES'S CONCERNS ADDRESSED

Q. Mr. Chiles indicated concern regarding some aspects of the Company's evaluation of need. What response do you have to that aspect of his testimony?

A. While verifying the Company's power flow analysis, and that the proposed Project resolves the identified reliability deficiencies, GDS outlined several concerns with the Company's power flow cases. I will address each of his concerns below.

<u>Power Flow Cases</u>

GDS identified an apparent inconsistency between the 2019 and 2020 power flow models and the 2015, 2015 and 2021 power flow models as they relate to the application of Rate B and Rate C in contingency studies. First as noted below:

1. Rate A is the normal 24-hour rating of the transmission facility,
2. Rate B is the eight-hour emergency rating of the transmission facility, sometimes referred to as the short-term emergency rating ("STE"); and
3. Rate C is a 15-minute load dump rating.

Prior to January 2012 the Company used 130% of its Rate B (STE) for identifying Category C or Category D criteria violations. Therefore, the Company's Summer 2019 and Summer 2020 Power Flow Models, conducted in the first quarter of 2011 as part of the Company 2011 Analysis, would never have had a Rate C for Company facilities, and the Category C and Category D reliability studies done for the Company 2011 Analysis would have used 130% of Rate B to determine a Category C or D criteria violation.

Consistent with a recommendation from a NERC/FERC Cyber Security audit, the

Company agreed to calculate a 15-minute load dump rating, referred to as the Rate C Rating for the Category C and D analysis. The calculation of a 15-minute Load Dump Rating is also consistent with PJM Operations rating methodology. This change was incorporated into the Company's Facility Connection Requirements Document and Facility Rating Methodology in December of 2011, as shown on my Rebuttal Schedule 8 (Exhibit A of the Company's Facility Connection Requirements Document). As studies for this Project progressed in 2012, this change was incorporated into the power flow models. The Summer 2015, 2016 and 2021 power flow models used in the Company 2012 Analysis incorporate these changes and were used as the most up-to-date analysis filed with the Company's Application. Therefore, any analysis of the 2019 and 2020 models for tower line outages would need to use 130% of Rate B to replicate studies done in the Company 2011 Analysis. But if trying to compare to the criteria used in the Company's 2012 Analysis, a 115% of Rate B provides a proxy for the Rate C methodology in use since January 1, 2012. As I noted earlier, the 2019 and 2020 power flow models from the Company 2011 Analysis were never used to analyze the transmission planning impacts of Yorktown and CEC retirements. At the request of Staff, these models were updated in the Company's response to Question No. 16 of the Staff's Second Set of Interrogatories, to include these retirements and the proposed Project and certain other Pre-Projects associated with those retirements. However, these models from the Company 2011 Analysis did not represent the topology in the study area reflected in the later PJM Analysis and Company 2012 Analysis.

GDS also raises some concerns about certain Pre-Projects outside of the study area which were not in the 2016 and 2021 power flow models used in the Company 2012

Analysis. Of these projects, only the Landstown Static VAR Compensator ("SVC"), located in the South Hampton Roads Load Area, is in proximity to the Project area. This SVC is being installed to resolve a voltage collapse for an outage of the Suffolk-Yadkin 500 kV Line followed by the outage of the Septa-Yadkin 500 kV Line (currently the Septa-Fentress 500 kV Line). This voltage collapse will not show up in an N-1-1 Analysis using MUST modeling software, so a more detailed system study is required for this analysis.

Tower Line Outages

As noted on page 15 of Mr. Chiles' testimony, in its analysis of Summer 2015 for the GDS 2013 Analysis, GDS could not verify the results of two tower line outages:

A. Outage of the Harrisonburg – Endless Cavers Tower Line #2017 & #2134 and

B. Outage of the Churchland – Sewells Point Tower Line #257 & #2099

Both of these tower line outages involve the same scenario, the outage results in the 230 kV source for both the Harrisonburg and Sewells Point Stations being lost. If the MUST Program is trying to solve the Contingency Condition with the Load Tap Changing ("LTC") option enabled, the 230-115 kV Transformers will try to continue to regulate the 115 kV low side voltages even though no 230 kV source is present, and the transformers will appear to overload. If this option is not enabled, however, the LTCs will not regulate voltages for contingency conditions and thus the transformers will not overload. Neither method of study, LTC Enabled or Disabled, is incorrect, and both provide valid results. The planner just needs to know the configuration of the transmission system being studied to interpret the study results.

Critical System Condition

GDS has expressed concerns regarding differences in some naming conventions used in the power flow cases regarding generation retirements for the PJM Analysis versus those used for the Company 2012 Analysis reflected in the Application. The PJM Analysis primarily looked at two different CSCs, the first being an outage of Yorktown Unit 3 and the second being an outage of the 230 kV Surry Unit 2. The PJM Analysis was a system level analysis that analyzed the impacts of generation retirements in both the North and South Hampton Roads Load Areas. A CSC power flow case with Yorktown Unit 3 off-line will have greater impacts on the transmission system in the North Hampton Roads Load Area. Conversely, a CSC power flow case based on the 230 kV Surry Unit 2 being off-line will have greater impacts on the transmission system in the South Hampton Roads Load Area. Both generating units will have similar impacts on the transmission system west of Richmond because the bulk power will be flowing from west to east. The PJM Analysis also included a sensitivity study for retirement of Yorktown Unit 2 because it is classified as an at risk unit. Therefore, the PJM Analysis for the North Hampton Roads Load Area was based on two basic generation scenarios: the first with Yorktown Unit 3 off-line and the second with Yorktown Units 2 and 3 off-line.

The power flow studies for Company 2012 Analysis (Summer 2015, Sumer 2016 and Summer 2021) used to support the Company's Application were based on two basic generation scenarios: the first with Yorktown Unit 3 off-line and the second with Yorktown Units 2 and 3 off-line. Whether a power flow case was labeled as a CSC, a CSC with generation sensitivity (as it was in the PJM Analysis) or as a basecase with Yorktown Unit 3 off-line and a CSC with Yorktown Unit 2 off-line, the same generation

CSCs were analyzed. The Company does acknowledge that the lack of consistent naming conventions for these two analyses can lead to confusion in interpreting the study results. While the Company did not file a CSC with Surry Unit 2 off-line, this 230 kV unit is not located in the North Hampton Roads Load Area and would have smaller impacts then a similar analysis with Yorktown Unit 3 off-line.

After the Application was filed in June of 2012, the Company announced in October of 2012 that Yorktown Unit 2 will retire by the end of 2014. GDS is correct that an updated analysis would have both Yorktown Unit 1 and 2 off-line in its base power flow case assumptions. However, such an updated power flow case would only increase the severity of the identified NERC Reliability Violations in the Company 2012 Analysis and increase the need for the proposed Project. Moreover, the CSC case (Yorktown Unit 2 off-line) essentially already provides these same results.

V. PRIOR CONSIDERATION OF 230 KV ALTERNATIVES

Q. What 230 kV alternatives to the proposed Project did the Company consider before filing its Application?

A. As noted on pages 56 through 61 of the Appendix the Company and or PJM evaluated eight different alternatives to the proposed Project. Several of these alternatives involved the construction of double circuit 230 kV lines, including both overhead and underground options. None of these alternatives was found to resolve all of the identified NERC Reliability Violations. As noted in response to Question Nos. 26 and 27 of the Staff's Third Set of Interrogatories, provided in my Rebuttal Schedules 9 and 10, respectively, the Company analyzed both the Summer 2016 and Summer 2021 Power Flow Cases to determine the effectiveness in both the short-term and long-term of the proposed Project and alternative projects.

Q. What specific transmission alternatives did JCC Witnesses Whittier or Middaugh present for the Commission to consider?

A. Primarily, James City County is indicating that an underground 230 kV transmission line(s) be constructed from Surry Station to Skiffes Station in lieu of the Project along the Proposed or Alternate Route. The Company, PJM and Staff Witness Chiles have thoroughly studied and rejected the 230 kV alternatives, but it appears James City County's primary rationale for support of a 230 kV alternative is to support an underground alternative to the Project, although they admit that it would not solve all of the identified NERC violations. James City County's position appears to advocate that the Company should build an underground 230 kV line and then resolve the remaining reliability deficiencies by making additional enhancements to the transmission system. As I have indicated above, the cost of any such additional enhancements would be in addition to the cost of undergrounding.

Q. Did the Company consider a 230 kV line(s) in lieu of the proposed Project along the Proposed or Alternate Route?

A. Yes, both the Company and PJM did consider 230 kV alternatives to the proposed 500 kV line. The Company considered both a double circuit 230 kV overhead alternative along the Proposed and Alternate Routes and a double circuit 230 kV underground alternative from Surry to Skiffes Creek. Company Witness Herling of PJM will address the reliability analysis that PJM conducted, including analyses of the 230 kV alternative projects submitted by merchant developers.

The Company did conduct a reliability analysis of the 230 kV alternatives included in the Appendix. As noted in the Company's response to Question No. 26 of the Staff's Third Set of Interrogatories, provided as my Rebuttal Schedule 9, there were several additional transmission facilities that would overload if a 230 kV line(s) from Surry was built in lieu of the proposed Surry to Skiffes Station 500 kV line or the Chickahominy to Skiffes Station 500 kV line.

Q. What were the additional NERC Reliability Violations that were identified if a double circuit 230 kV overhead or underground line were constructed?

A. The proposed Skiffes Creek to Yorktown 230 kV line (to be created by splitting existing 230 kV Waller to Yorktown Line #209 at Skiffes Station), the Suffolk 500-230 kV Transformers #1 and #2, and the proposed Skiffes Creek to Yorktown 115 kV Line (to be created by splitting existing 115 kV Lanexa to Yorktown at Skiffes Station) would overload.

Q. JCC Witnesses Whittier and Middaugh mention alternative proposals made by Northeast Transmission, a subsidiary of LS Power, to PJM, found at page 76 of the Company's Appendix. Can you comment?

A. Yes, both Mr. Whittier and Mr. Middaugh mention 230 kV proposals of LS Power, a non-incumbent transmission developer, to PJM. LS Power proposed a single circuit hybrid Surry-Skiffes Station 230 kV line with and without a phase angle regulator ("PAR") to resolve the NERC Reliability Violations identified in the North and South Hampton Roads Load Areas. As noted in PJM's Transmission Expansion Advisory Committee ("TEAC") Presentation on April 27, 2012 (see Appendix Attachment I.C.2), PJM found the LS Power proposals inferior to the Company's proposed Surry 500 kV and Chickahominy 500 kV proposals. Company Witness Herling of PJM will discuss PJM's analysis of these transmission alternatives in greater detail in his testimony.

Q. Why did PJM reject the LS Power Proposals?

A. As PJM identified in its reliability analysis, the LS Power proposals did not resolve all of the identified reliability deficiencies for the CSCs (Generation Scenarios) that PJM studied, and Mr. Herling will discuss that in greater detail. Also, as PJM identified in the TEAC process, the operational performance of Phase Angle Regulator ("PAR"), which LS Power proposed in an attempt to remedy the failure of its initial proposal to resolve all of the identified NERC violations resulted in additional transmission facilities being overloaded. PARs are a major concern when operated in the interconnected transmission system and are especially troublesome in applications like the LS Power proposal, where the main function of the PAR is to prevent either the proposed overhead or underground 230 kV line from Surry from overloading for transmission contingencies. Mr. Herling of PJM will provide more detail as to the efficacy of using a PAR as proposed by LS Power.

I would also note that LS Power presented the cost of its PAR as $15 million and did not indicate whether that figure included a spare, which would be required.

Q. Did the Company have any other concerns with the proposed LS Power PAR Application?

A. Yes. The application of a PAR on the transmission system is a unique application and the PAR Transformer its self is not a typical transformer that is manufactured. Therefore, the cost and lead time of a PAR transformer is inherently expensive and long. The LS Power proposal appears to significantly underestimate this cost. For example, if the

Company were going to purchase a 1000 MVA PAR to put in-series with a 1000 MVA 230 kV transmission line the estimated cost for such a transformer is $35M with an installed cost $47M and a projected lead-time of approximately 24 months. As noted in the TEAC presentation this application is likely to result in additional transmission deficiencies because the purpose of this application is to prevent the series element from being overloaded.

Q. Does Mr. Whittier discuss any other 230 kV transmission alternative that Dominion Virginia Power might consider?

A. Yes, he does. On pages 10-13 of his testimony, JCC Witness Whittier suggests a rebuild of the Company's existing Newport News Crossing of the James River by existing 230 kV two Lines #214 and #263 with an estimated total cost of $99 million. This Alternative, which has been identified as 230 kV Alternative C, is estimated to cost $144.8M and does not resolve all the identified NERC Reliability Deficiencies in 2015. Alternative C requires an additional $264 million in transmission projects to make it compliant with NERC Reliability Standards plus $383 - $652 million of additional generation-related construction expenditures and still cannot be constructed until after 2020.

Q. If the Company took Mr. Whittier's proposed approach, would it have been compliant with NERC Reliability Standards?

A. No. This suggested approach would not have been NERC-compliant, and analysis of the power flow case that Mr. Whittier provided in response to Question No. 33 of the Company's First Set of Interrogatories, contained in my Rebuttal Schedule 11, confirmed that the proposed solution did not resolve the NERC Reliability Violations identified in the Application. Mr. Whittier's proposed rebuild of the existing James River crossing circuits does not eliminate the need to comply with the NERC Category C.3 (Tower Line) analysis because Line #214 and #263 are still located on the same structures.

VI. OTHER JAMES CITY COUNTY COMMENTS

Q. Have either JCC Witnesses Whittier or Middaugh conducted any reliability analysis to support any aspect of their testimony?

A. No. Based on their filed testimony, neither Mr. Whittier nor Mr. Middaugh has conducted a comprehensive reliability analysis to support any aspect of their testimony or to refute the Company 2012 Analysis, the results of which were presented on pages 23-54 of the Appendix supporting the Company's Application. Mr. Whittier does state on page 4 of his testimony that he did not conduct any additional analysis on behalf of James City County. Also included as my Rebuttal Schedule 12 and Rebuttal Schedule 13, respectively, are the responses by Mr. Whittier to Questions Nos. 34 and 35 of the Company's First Set of Interrogatories, which confirm he did not conduct additional reliability analyses after his testimony was filed in this proceeding.

Q. Does James City County object to the Company's identification of NERC Reliability Violations for 2015 or the need to resolve them in order to comply with mandatory NERC Reliability Standards?

A. No. Nowhere in the testimony of the JCC witnesses does any witness appear to object to the electrical need identified by the Company. James City County's objections appear to be directed to any overhead crossing of the James River to Skiffes Station to meet that need.

Q. Does James City County object to the need for the Skiffes Station?

A. No, James City County does not appear to object to the need for the Skiffes Station. In fact, both JCC Witnesses Whittier and Middaugh discuss transmission alternatives that would still require the construction of the Skiffes Station, and some of their alternatives may require that additional transmission equipment be installed in the Skiffes Station.

Q. Does Mr. Whittier have any other suggestions?

A. Yes, Mr. Whittier briefly expresses the view that energy efficiency or demand side management programs may not have been considered. Company Witness Herling will discuss how these programs are already incorporated into the PJM Load Forecast and PJM's current experience with these programs. Participation in energy efficiency or demand-side management programs by customers is strictly voluntary in that the Company cannot mandate that customers participate in these programs. While Mr. Whittier is correct that the Peninsula is a highly developed area, the customers located in this area like Busch Gardens Williamsburg, Anheuser Busch Brewery, Colonial Williamsburg, Newport News Shipbuilding and Water Country USA need to make their own decisions if they want to participate in demand-side management programs, interruptible contracts or energy efficiency programs, especially during peak summer and winter loading periods. In any event, Mr. Herling's rebuttal testimony states that only 13.3 MW of demand resources in the North Hampton Roads Load Area were available for PJM during the 2012 summer peak period having committed through previous RPM auctions.

Q. Does Mr. Whittier provide any comments indicating that NERC Reliability Standards do not need to be complied with?

A. Yes. On page 8 of his testimony, Mr. Whittier states that a right-of-way outage should only be evaluated for possible actions that could mitigate their consequence but that a right-of-way outage need not be resolved. This course of logic ignores NERC's stated purpose of NERC Category D Assessments: "Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs."[2] This requirement is further emphasized in the new NERC Planning Standard, which is awaiting final approval at FERC. Requirement R3 3.5 states that "those extreme events in Table 1 that are expected to produce more severe System impacts shall be Identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting Information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."[3]

Any entity that makes a reliability assessment determining that a required criteria evaluation results in an unacceptable system performance and then knowingly chooses to

[2] NERC Transmission Reliability Standards, Standard TPL-004-0 – System Performance Following Extreme BES Events, Requirement R1.

[3] NERC Transmission Reliability Standard, Standard TPL – 001 –02 Transmission System Planning Performance Requirements, http://www.nerc.com/docs/standards/sar/atfnsdt_recirc_ballot_tpl_001_2_clean_20110711.pdf

proceed with a transmission project that does not resolve the deficiency, when viable alternatives are available that would resolve it, is going to be found in violation of NERC Reliability Standards. In this case, both the Company's proposed Project and the Chickahominy Alternative would resolve the identified deficiency in compliance with NERC Reliability Standards.

VII. SKIFFES STATION IS A "TRANSMISSION LINE" FOR THE PURPOSES OF VA CODE § 56-46.1 F

Q. What response do you have to the testimony of the JCC witnesses who have asserted the need for the Company to obtain a Special Use Permit in order to construct the Skiffes Station?

A. This issue, raised by JCC Witness Middaugh and Reidenbach, is addressed in the rebuttal testimony of Company Witness Elizabeth Harper, the Company's siting and permitting witness for this Project, who explains that such an approval is not required for a transmission line approved by the Commission under Va. Code § 56-46.1. I can say, without qualification, is that the Skiffes Station is and should be considered a "transmission line" for the purposes of that statute.

The purpose of this Project is to deliver bulk power at 500 kV into the 230 kV system by connecting the 500 kV system to the 230 kV system at Skiffes Station. Skiffes Station, which will contain only transmission facilities and is classified as part of the Bulk Electric System ("BES") by NERC, will accomplish this task by connecting the new 500 kV Skiffes Creek line with the proposed 230 kV Skiffes Creek-Whealton line, which will deliver the additional capacity and energy to load down the Peninsula. This connection cannot be accomplished by merely connecting the cables of both lines as they are installed on the structures that support them. This is for two reasons. First, the lines will operate at different transmission voltages, so the power from the 500 kV line must be transformed to 230 kV before it can be received by the 230 kV facilities of the new line to Whealton. Second, switching equipment is needed to permit the Company to control the flow of power between the two lines. A switching station is required to contain the equipment required to accomplish these vital tasks safely and efficiently to maintain the reliability of the interconnected transmission system.

Section II.C of the Appendix and the prefiled testimony of Company Witness Tony Spears describes the 500 kV, 230 kV and 115 kV buses and associated other conductors and supporting backbones and switches and other equipment that make up Skiffes Station. Power is delivered to Skiffes Station from Surry at 500 kV to be carried and delivered, after transformation, to the 230 kV bus for carriage and delivery to the new line extending from Skiffes Station to Whealton. In addition, the 230 kV bus is used to carry and deliver power to the existing 230 kV lines that are split at and extend from Skiffes Station to distant points. After further transformation, the 230 kV bus carries and delivers power to the 115 kV bus for delivery to the existing lines that are split at and extend from Skiffes Station to distant points.

These types of switching station transmission facilities are required by NERC, as part of the NERC Reliability Standards, for all transmission owners, transmission planners and transmission operators to maintain continued safe and reliable operation of the interconnected transmission system. Accordingly, neither of these proposed lines could, or would, be constructed or operated without the switching station, which is integral to those lines. Physically and operationally, the Skiffes Station is an inseparable part of the proposed 500 kV and 230 kV lines. Moreover, the specific facilities at Skiffes Station function as a transmission line as that term is defined by NERC:

> A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.[4]

Q. Will it also affect other transmission lines?

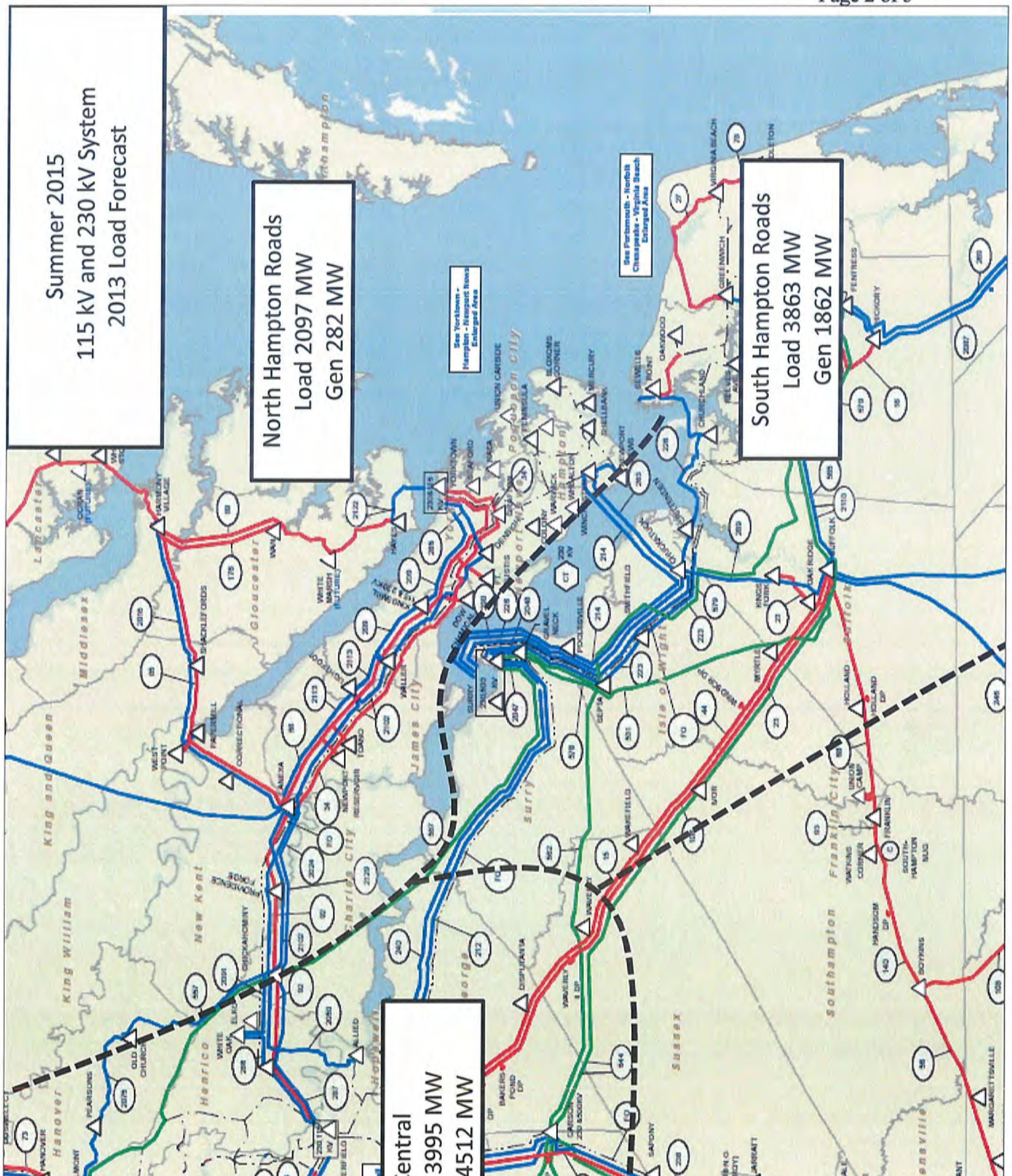
A. Yes. The switching station site is located at a point where two existing 230 kV lines and an existing 115 kV line are in close proximity, which provides the opportunity to shorten, and thereby improve the reliability of those lines, and the operating flexibility of the transmission system. The station will include equipment to split these two 230 kV lines to receive power at 230 kV and also equipment to transform power from the 230 kV bus to 115 kV for delivery to the existing 115 kV bus for redelivery to the existing 115 kV line, which will be split for that purpose.

Q. Mr. Nedwick, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

[4] Available at www.nerc.com/files/glossary-of-terms.pdf.

Schedule One
Area Diagram


Summer 2015
115 kV and 230 kV System
2013 Load Forecast
North Hampton Roads
Load 2097 MW
Gen 282 MW
South Hampton Roads
Load 3863 MW
Gen 1862 MW
Central
Load 3995 MW
Gen 4512 MW

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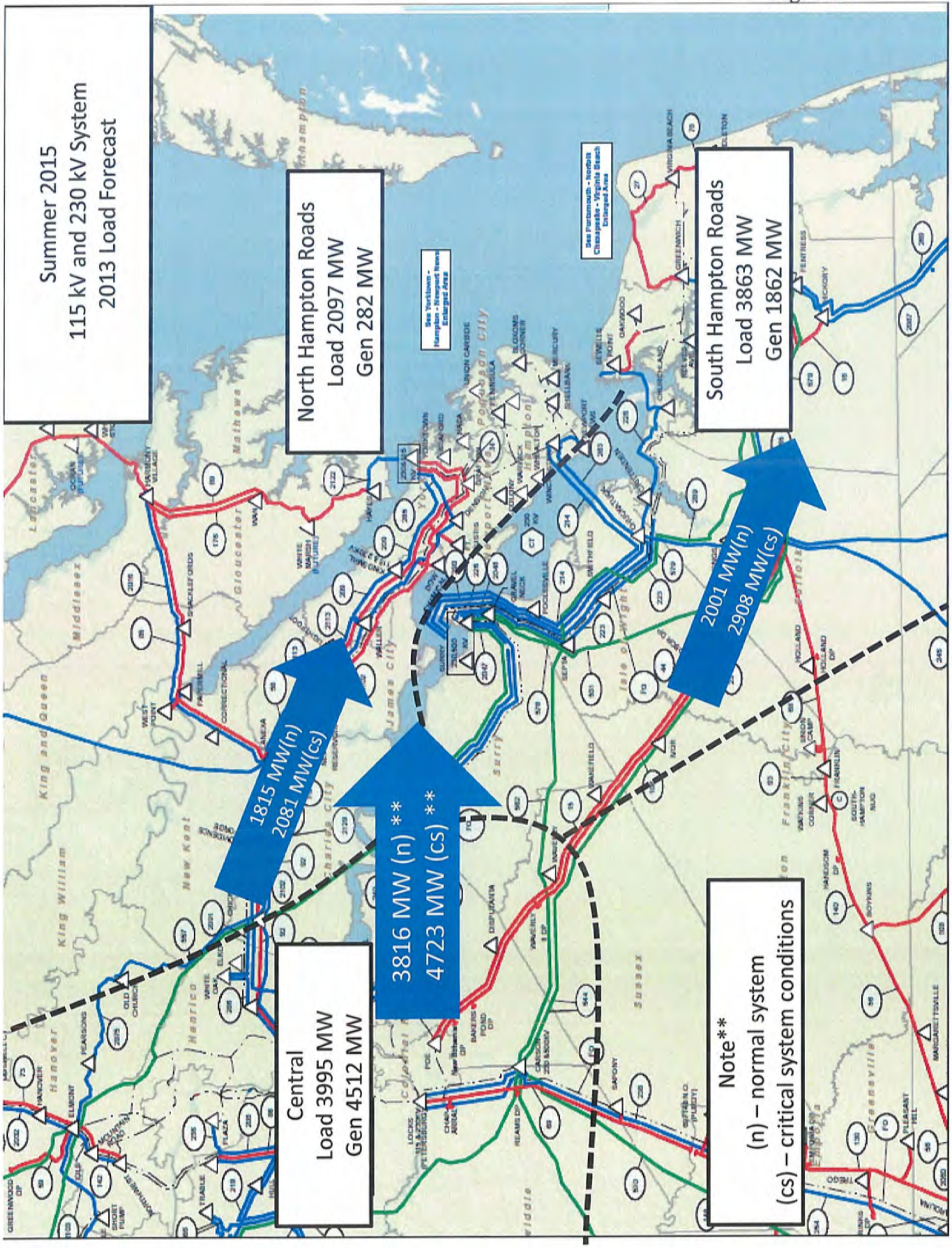

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 1
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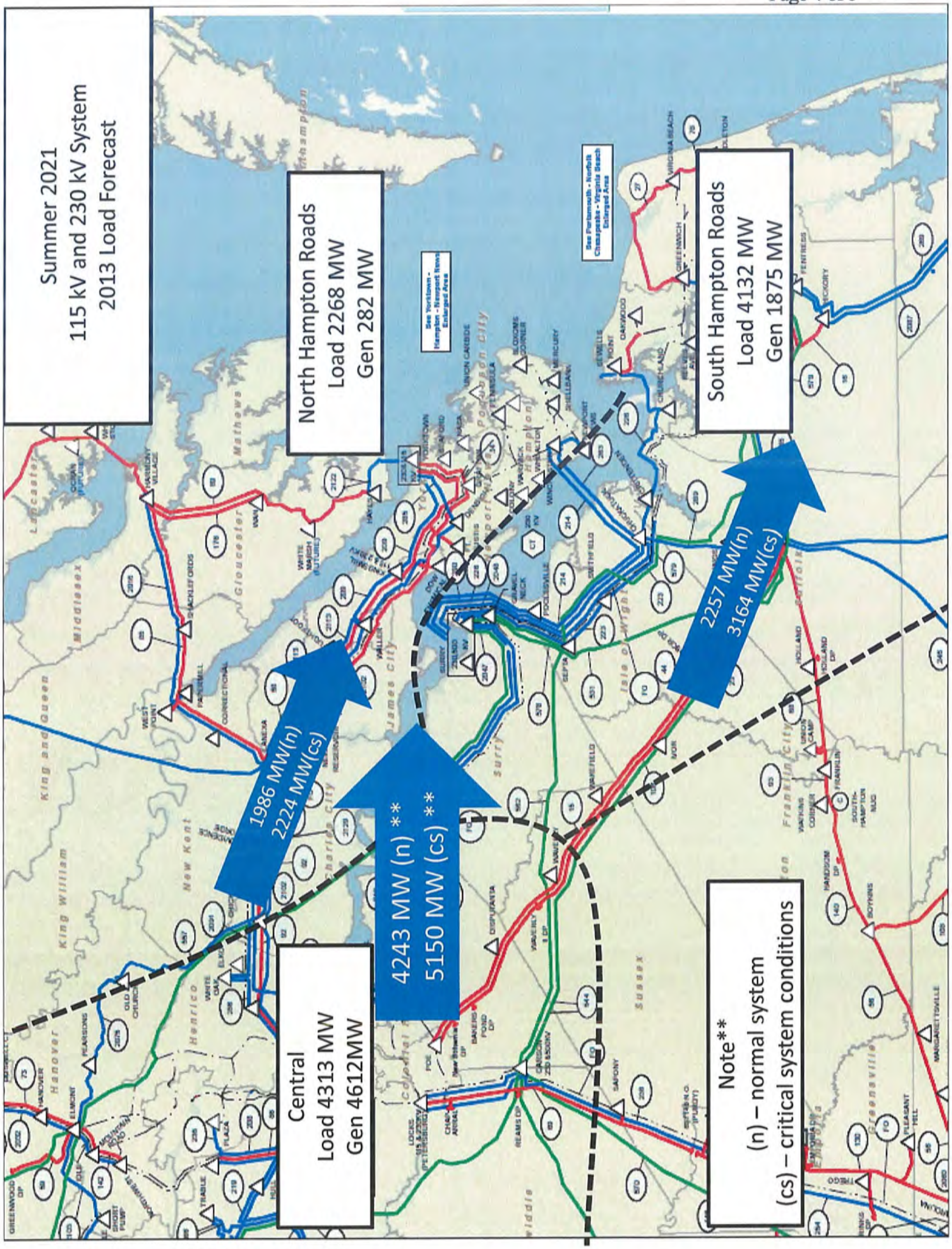


FUTURE CAPACITY IMPORTS FROM WEST OF RICHMOND TO NORTH AND SOUTH HAMPTON ROADS LOAD AREAS

	Normal Conditions		Critical System Condition	
2015	Capacity Required from West of Richmond	% of Capacity Required from West of Richmond	Capacity Required from West of Richmond	% of Capacity Required from West of Richmond
North & South Hampton Roads (combined)	3816 MW	64%	4723 MW	81%
North Hampton Roads	1815 MW	86.6%	2081	99%
South Hampton Roads	2001 MW	52%	2908	75%
2021	Capacity Required from West of Richmond	% of Capacity Required from West of Richmond	Capacity Required from West of Richmond	% of Capacity Required from West of Richmond
North & South Hampton Roads (combined)	4243 MW	66.3%	5150 MW	80.5%
North Hampton Roads	1986MW	87%	2224 MW	98%
South Hampton Roads	2257 MW	54.6%	3164 MW	76.6%

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 2

Revised Study #	Study Year	Units Retired[6]	Critical System Condition[5]	Proposed Projects Included	Study
Alternative Analysis[2, 3, 4]					
Alternatives Studied 500 kV Proposed - Surry to Skiffes Creek 500 kV Overhead Alternative A - Single Circuit 230 kV UG Line based on 1000 MVA Alternative B - Double Circuit 230 kV UG Line based on 1000 MVA					
1	2015	All retirements	No CSC	Base[7]	500 kV Proposed[9]
2	2015	All retirements	SU2	Base[7]	500 kV Proposed[9]
3	2015	All retirements	No CSC	Base[7] + Project	500 kV Proposed[9]
4	2015	All retirements	SU2	Base[7] + Project	500 kV Proposed[9]
5	2015	All retirements	SU1	Base[7]	230 kV Alternatives[9]
6	2015	All retirements	No CSC	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV Alternatives[9]
7	2015	All retirements	SU1	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV Alternatives[9]
8	2021	All retirements	No CSC	Base[7]	500 kV Proposed
9	2021	All retirements	SU2	Base[7]	500 kV Proposed
10	2021	All retirements	No CSC	Base[7] + Project	500 kV Proposed
11	2021	All retirements	SU2	Base[7] + Project	500 kV Proposed
12	2021	All retirements	SU1	Base[7]	230 kV Alternatives
13	2021	All retirements	No CSC	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV Alternatives
14	2021	All retirements	SU1	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV Alternatives
Generation Alternative Analysis[2, 3, 4]					
Special Study Condition Yorktown Unit 3 to be used as proxy generation to study two 230 kV UG alternatives Alternatives Studied Alternative A - Single Circuit 230 kV UG Line based on 1000 MVA Alternative B - Double Circuit 230 kV UG Line based on 1000 MVA per circuit					
15	2015	All retirements	No CSC	Base[7]	230 kV + Generation[8, 9]
16	2015	All retirements	SU1	Base[7]	230 kV + Generation[8, 9]
17	2015	All retirements	No CSC	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV + Generation[8, 9]
18	2015	All retirements	SU1	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV + Generation[8, 9]
19	2021	All retirements	No CSC	Base[7]	230 kV + Generation[8]
20	2021	All retirements	SU1	Base[7]	230 kV + Generation[8]
21	2021	All retirements	No CSC	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV + Generation[8]
22	2021	All retirements	SU1	Base[7] + Alt. A/Alt. B/Alt. C[1]	230 kV + Generation[8]
Analysis of Proposed 500 kV Without Retirements[2,3, 4]					
Alternatives Studied 500 kV Proposed - Surry to Skiffes Creek 500 kV Overhead					
23	2021	No retirements	No CSC	Base[7]	500 kV Proposed
24	2021	No retirements	SU2	Base[7]	500 kV Proposed
25	2021	No retirements	No CSC	Base[7] + Project	500 kV Proposed
26	2021	No retirements	SU2	Base[7] + Project	500 kV Proposed

Notes

1. 230 kV Alternative A - Single Circuit 230 kV UG Line based on 1000 MVA
   230 kV Alternative B - Double Circuit 230 kV UG based on 1000 MVA per circuit
   230 kV Alternative C - Rebuild of Line ## 214 and 263 as per Whittier
2. Load for Dominion System based on 2013 PJM Load Forecast
3. PSS/MUST system definition files (.sub, .mon) - encompass entire DVP System area 345
   .con file - Single Branch, Breaker to Breaker, Tower Line encompass entire DVP System area 345
   .con File - N-1-1 utilize zones 354(Northern Neck), 356(Yorktown), 359(Va Beach), 360(Suffolk) and 366(500 kV)
4. Reliability Assesment utilize Dominion's current transmission reliability planning standards including RateA, RateB and RateC
5. Abbreviations
   CEC1 Chesapeake Unit 1
   CEC2 Chesapeake Unit 2
   CEC3 Chesapeake Unit 3
   CEC4 Chesapeake Unit 4
   YORK1 Yorktown Unit 1
   YORK2 Yorktown Unit 2
   YORK3 Yorktown Unit 3
   CSC - SU1 Critical System Condition - Surry Unit 1 (230 kV)
   CSC - SU2 Critical System Condition - Surry Unit 2 (500 kV)
6. Generation Retirements

CEC1 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
CEC2 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
CEC3 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
CEC4 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
YORK1 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
YORK2 Retire by 2015	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4
YORK3 Retrofit by 2018*	DVP IRP 2012 Plan Figure 1.4.1/Figure 1.4.4

   *Note 2018 retrofit doesn't change DVP response to Staff 3-30

7. Base case includes the following Pre-projects
   Bus Yadkin 500 kV
   Add 3rd 500-230 kV Tx at Yadkin
   Install 2nd 230-115 kV Tx at Yadkin
   Install 2nd 230-115 kV Tx at Chesapeake
   Uprate Line #46 (Yadkin to Chesapeake)
   Suffolk to Yadkin 230 kV Line
   Clover 3rd 500-230 kV Tx
   Rebuild Line #555 (Dooms to Lexington)
   Uprate Line #2027
   Install 2nd Valley 500-230 kV Tx
   Install Landstown 230 kV SVC
8. Transfer Studies
   For revised study cases 15-22, conduct a 804 MW transfer from DVP generation to YORK3 (YORK3 being dispatched at 804MW). The purpose of these studies is to determine the minimum generation amount needed at Yorktown to meet the reliability criteria with the 230 kV Transmission + YORK Generation option.
   The minimum generation solution will be refined by conducting the AC contingency analysis with same premises from Notes 1 - 7 (YORK3 dispatched at the needed amount).
9. 2015 Base Case models (pre-retirement)
   All voltage and thermal violations identified from the analysis of 2015 retirement cases,
   are generated by the retirement of Chesapeake and Yorktown generation units

GENERATION STUDIES METHODOLOGY
Case No. PUE-2012-00029

Purpose:

The Hearing Examiner's Ruling of January 30, 2013, directed the Company to evaluate certain combinations of generation and transmission to resolve the mandatory NERC Reliability Violations related to the Yorktown Unit 1 and 2 generation retirements. Specifically, Alternatives A, B and C were to be modeled, and generation was to be added at the Yorktown 230 kV bus, to determine the minimum amount of generation needed to resolve any remaining NERC Reliability Violations. A stand-alone generation alternative also was to be developed under which generation was to be added at the Yorktown 230 kV bus to determine the minimum amount of generation needed to resolve all of the NERC Reliability Violations.

Study Methodology:

The same basic process/procedure was used with the MUST Program to develop all of the power flow cases for these generation studies. Alternative A will be used as an example. Power Flow Case 6A (Alternative A) was used as a starting point, with Yorktown Unit 3 (used only as a proxy for generation injection) initially dispatched at 838 MW and then generation in the entire Dominion System (Area 345) reduced by 838 MW to keep the system balanced. The net effect of this generation reduction was that the starting generation injection number for the Yorktown 230 kV bus was 808 MW. This new power flow case became Study 17A and this same procedure was repeated for Alternatives B and C, which became Studies 17B and 17C respectively. This same procedure was used for the Surry 230 kV Unit 2 off-line Critical System Condition ("CSC") Studies 7A, B and C to create Studies 18A, B and C, respectively. For the

Summer 2021 studies, Power Flow Studies 13A, B and C were used to create Power Flow Studies 21A, B and C, respectively, and Power Flow Cases 14A, B and C were used to create the CSC Surry 230 kV Unit off-line Studies 22A, B and C, respectively.

The Transfer Function of the MUST Program was used to calculate when generation could be reduced no further before a reliability deficiency occurred. This was done by increasing generation in the entire Dominion System and reducing the generation that was added at the Yorktown 230 kV bus. The Must Program then calculated a First Contingency Incremental Transfer Capability ("FCITC"). This is the same methodology used in studies to determine transfer capability between utilities or Regional Transmission Organizations ("RTOs").

For example, the study is repeated a total of five times to evaluate the Category B, Category B (with CSC), Category C Tower Line, Category C N-1-1 and Category D Cases. Attachments One, Two, Three and Four summarize the study results for Alternatives A, B and C and the Stand-Alone Generation Option for Summer 2015 and Summer 2021, respectively.

Attachment Five provides a copy of the subsystem file that was used in the transfer studies, and Attachment Six provides a copy of the monitor file that determined which zones were monitored for the transfer study. Only the lines and transformers in the North Hampton Roads Load Area and the 500 kV system were monitored because the purpose of the study was to determine the amount of hypothetical generation required to maintain compliance with NERC Reliability Standards in this load area.

Study Results:

Two different values need to be analyzed for each generation alternative studied, and each study year needs to also be analyzed. First, the largest generation value needs to be determined. When looking at Attachment One for Alternative A for Summer 2015, this value is 1,008 MW. The second value to be analyzed is the generation value associated with the Category B Analysis. If this value is greater than zero, it also indicates the minimum size of a generating unit that must remain in service if the largest proposed new hypothetical generating unit is out of service. The generation requirements for each alternative are summarized below.

	Alternative A	Alternative B	Alternative C	Stand-Alone Option
2015				
MW Required	1008	159	522	620
MW Size of smallest unit that must remain in service	0	0	56	295
2021				
MW Required	1449	551	505	618
MW Size of smallest unit that must remain in service	87	27	139	295

Attachment One

Alternative A
Single Circuit 230 kV UG 1000 MVA

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2015					
Start Gen	808	808	808	808	808
- FCITC	862	651	832	656	-200
Required Gen	-54	157	-24	152	**1008**

Summer 2015 Total Generation needed **1008 MW**
Outage of largest unit must leave **0 MW** on-line (CSC)

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2021					
Start Gen	808	808	808	808	808
- FCITC	721	803	611	270	-641
Required Gen	**87**	5	197	538	**1449**

Summer 2021 Total Generation needed **1449 MW**
Outage of largest unit must leave **87 MW** on-line (CSC)

Attachment Two

Alternative B
Two 230 kV UG Circuits 1000 MVA/circuit

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2015					
Start Gen	808	808	808	808	808
- FCITC	838	698	896	649	1382
Required Gen	-30	110	-88	**159**	-574
Summer 2015	Total Generation needed **159 MW** Outage of largest unit must leave **0 MW** on-line (CSC)				

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2021					
Start Gen	808	808	808	808	808
- FCITC	781	852	839	257	1312
Required Gen	**27**	-44	-31	**551**	-504
Summer 2021	Total Generation needed **551 MW** Outage of largest unit must leave **27 MW** on-line (CSC)				

Attachment Three

Alternative C
Line #214 & #263 Rebuild Option

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2015					
Start Gen	808	808	808	808	808
- FCITC	752	286	460	408	460
Required Gen	**56**	522	348	400	**348**

Summer 2015 Total Generation needed **522 MW**
Outage of largest unit must leave **56 MW** on-line (CSC)

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2021					
Start Gen	808	808	808	808	808
- FCITC	669	329	360	303	360
Required Gen	**139**	479	448	**505**	448

Summer 2021 Total Generation needed **505 MW**
Outage of largest unit must leave **139 MW** on-line (CSC)

Attachment Four

Stand Alone Generation Option

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2015					
Start Gen	808	808	808	808	808
- FCITC	513	188	460	346	459
Required Gen	**295**	**620**	348	462	349

Summer 2015 Total Generation needed 620 **MW**
Outage of largest unit must leave **295 MW** on-line (CSC)

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2021					
Start Gen	808	808	808	808	808
- FCITC	513	190	366	309	366
Required Gen	**295**	**618**	442	499	442

Summer 2021 Total Generation needed **618 MW**
Outage of largest unit must leave **295 MW** on-line (CSC)

Attachment Five
Study System *.Sub File

```
SUBSYSTEM 'york'  /* VP IMPORT 838 (GEN. SENSITIVITY)
   SCALE FOR IMPORT
     BUS 315092              /*
     END
  end
SUBSYSTEM 'peninsula'       /* dvp
   zone 354
   zone 356
   zone 359
   ZONE 360
   zone 366
  END
SUBSYSTEM 'DVP'  /* DVP Export
   Zone 351
   Zone 352
   Zone 353
   Zone 354
   Zone 355
   Zone 357
   Zone 358
   Zone 359
   Zone 360
   Zone 361
   Zone 362
   Zone 363
   Zone 364
   Zone 365
   Zone 366
   END
  END
 END
```

Attachment Six
System Monitor File

```
Monitor Branches in zone 356
monitor ties from zone 356
Monitor Branches in zone 366
monitor ties from zone 366
Monitor Branches in zone 354
monitor ties from zone 354
monitor voltage range bus 314232 0.974 1.04
monitor voltage range bus 314918 1.01 1.08
monitor voltage range bus 314538 0.957 1.04
monitor voltage range bus 314924 1.01 1.06
monitor voltage range buses 315001 315300 0.95 1.05
monitor voltage range zone 366 1.01 1.08
monitor voltage range area 345 0.93 1.07
monitor voltage deviation area 345 .05 .05
monitor voltage deviation bus 314232 .035 .035
monitor voltage deviation bus 314918 .035 .035
monitor voltage deviation bus 314538 .06 .06
monitor voltage deviation bus 314924 .045 .045
end
```

Dominion

PUE-2012-00029

2013 Power Flow Cases Requested by Hearing Examiner

Additional Analyses Conducted

- **500 kV Proposed** - Surry to Skiffes Creek 500 kV Overhead
- **Alternative A** – Hybrid Single Circuit 230 kV UG Line based on 1000 MVA
- **Alternative B** – Hybrid Double Circuit 230 kV UG Line based on 1000 MVA/circuit
- **Alternative C** - Rebuild of Lines #214 and #263

Dominion

Additional Analyses Conducted

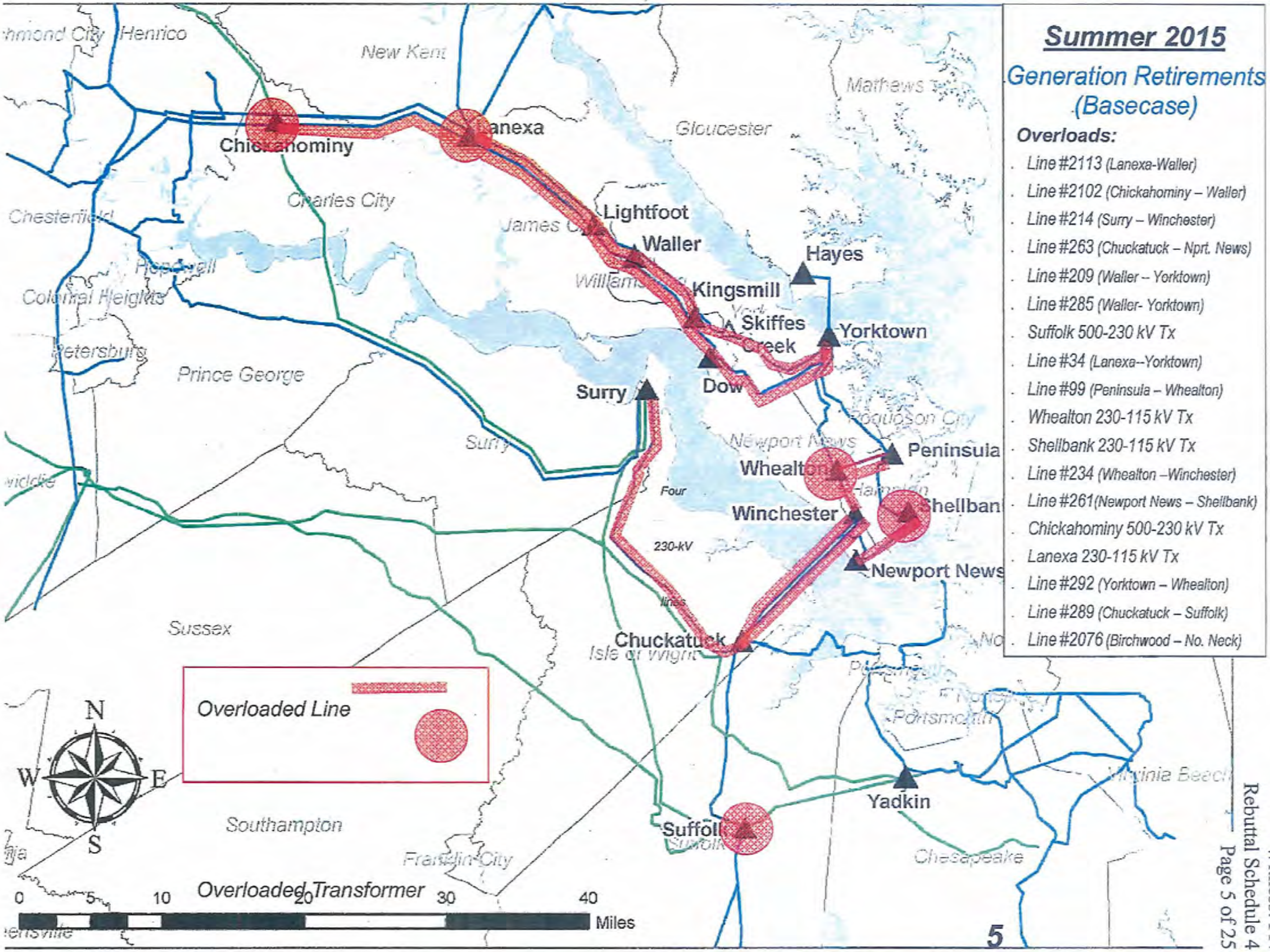
- **Alternative A** – Hybrid Single Circuit 230 kV UG Line based on 1000 MVA Plus Generation
- **Alternative B** – Hybrid Double Circuit 230 kV UG Line based on 1000 MVA/circuit Plus Generation
- **Alternative C** - Rebuild of Lines #214 and #263 Plus Generation
- **Stand Alone Generation** – Add generation to Yorktown

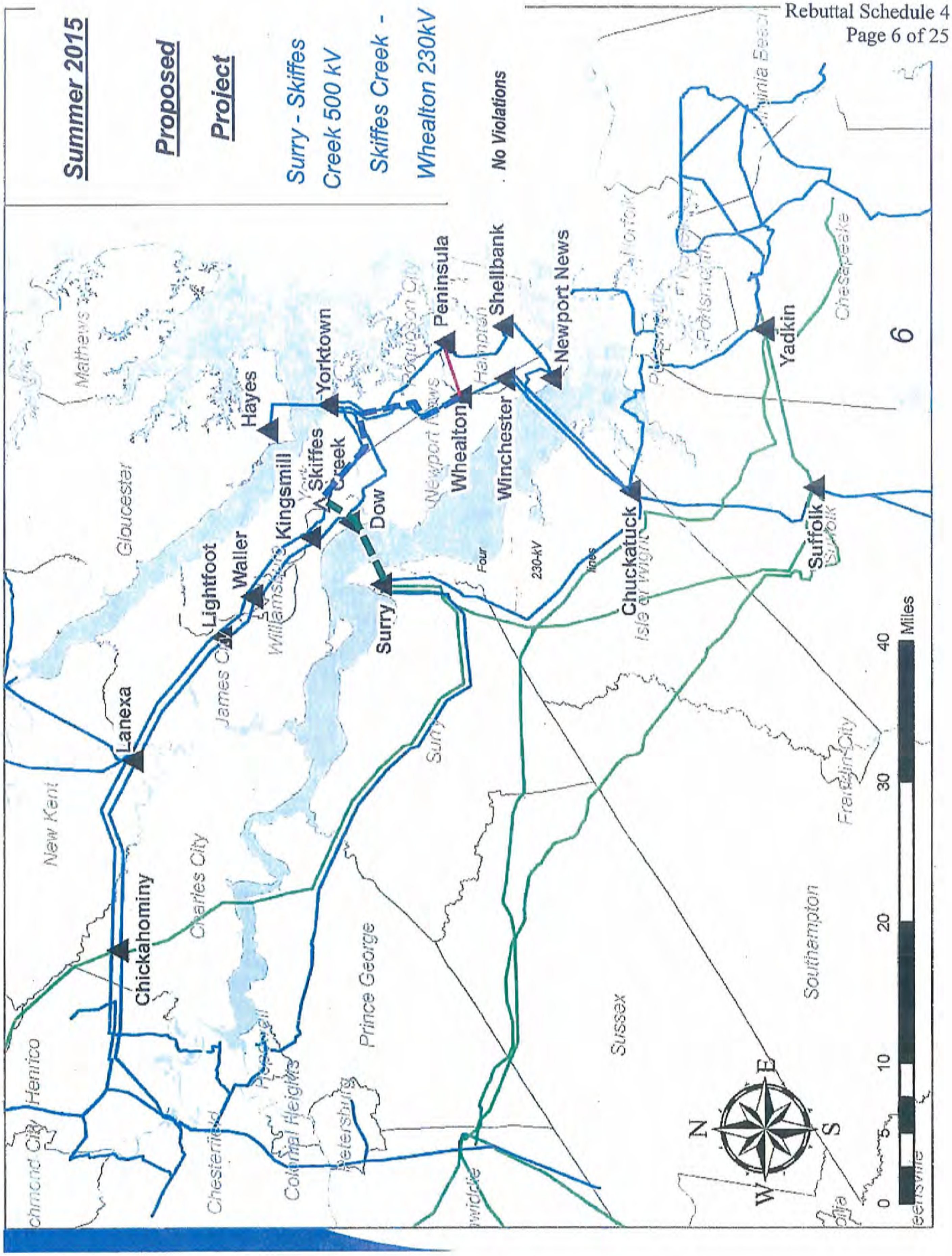
Dominion

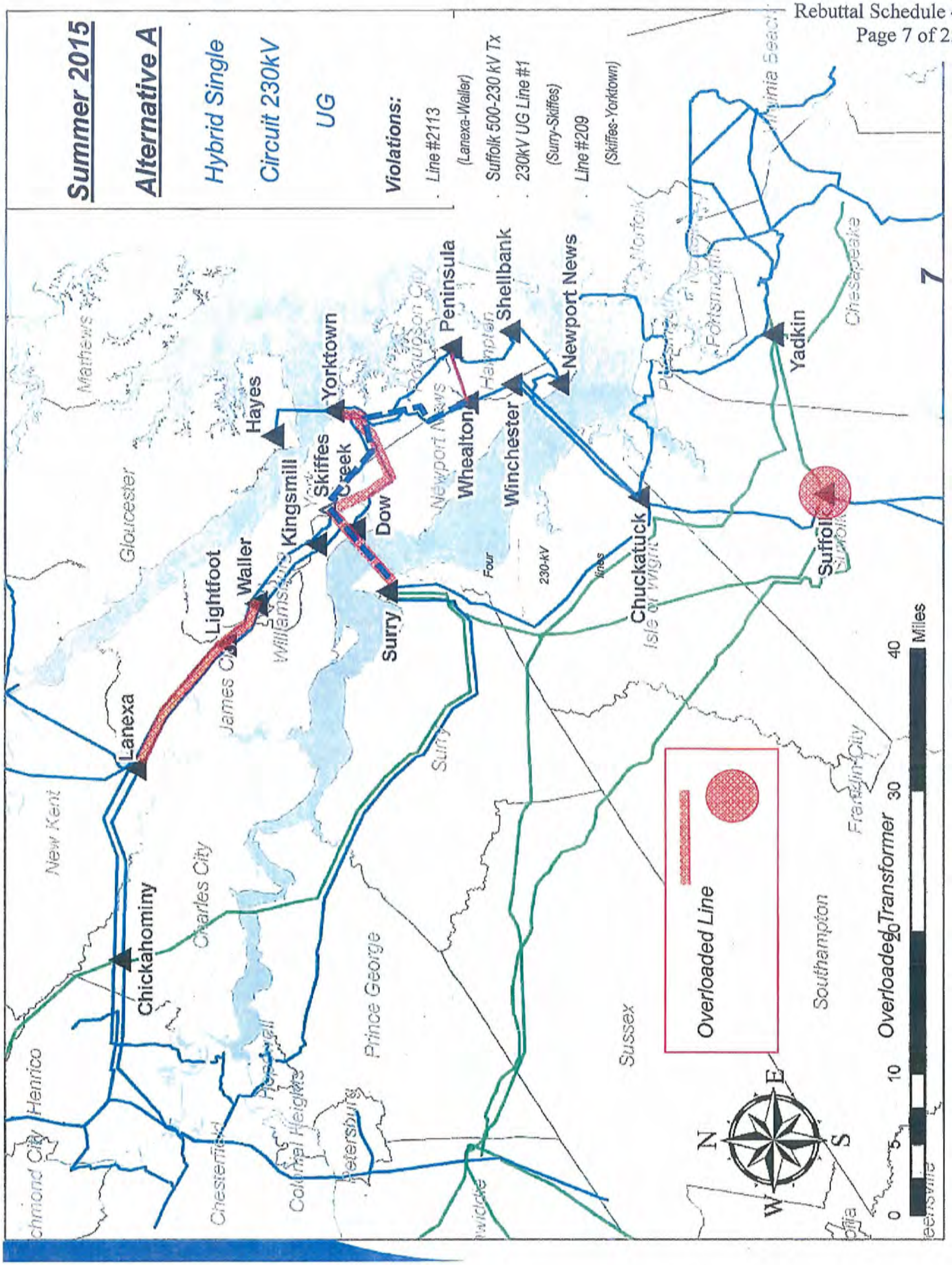
Assumptions

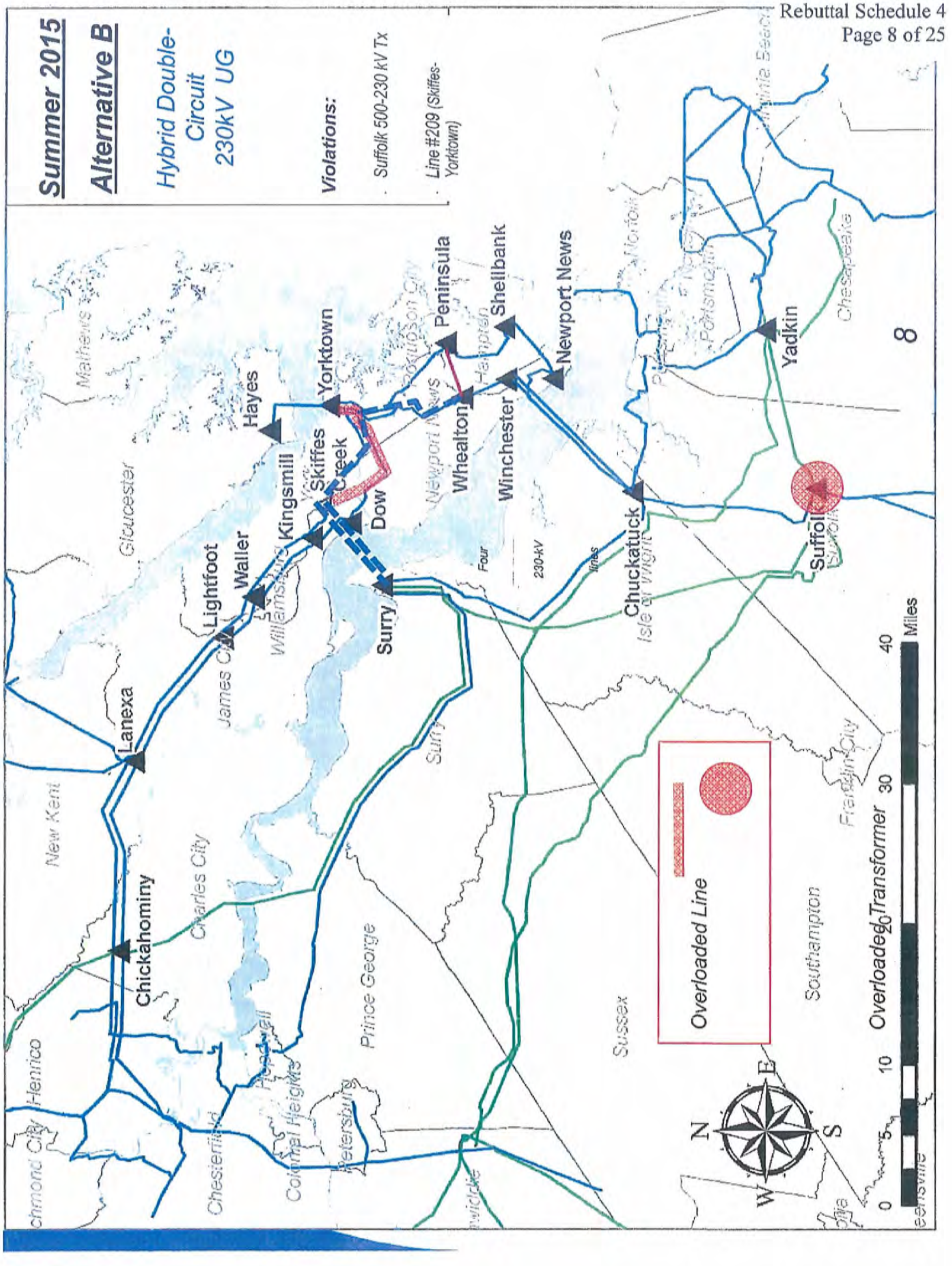
- Consistent with Hearing Examiner's January 30 Ruling as set forth in Rebuttal Schedule 2 of Company Witness Nedwick's Rebuttal Testimony

Dominion


Summer 2015
Generation Retirements (Basecase)
Overloads:
Line #2113 (Lanexa-Waller)
Line #2102 (Chickahominy – Waller)
Line #214 (Surry – Winchester)
Line #263 (Chuckatuck – Nprt. News)
Line #209 (Waller – Yorktown)
Line #285 (Waller- Yorktown)
Suffolk 500-230 kV Tx
Line #34 (Lanexa--Yorktown)
Line #99 (Peninsula – Whealton)
Whealton 230-115 kV Tx
Shellbank 230-115 kV Tx
Line #234 (Whealton –Winchester)
Line #261 (Newport News – Shellbank)
Chickahominy 500-230 kV Tx
Lanexa 230-115 kV Tx
Line #292 (Yorktown – Whealton)
Line #289 (Chuckatuck – Suffolk)
Line #2076 (Birchwood – No. Neck)
Henrico
New Kent
Mathews
Gloucester
Chesterfield
Charles City
Colonial Heights
Prince George
Sussex
Southampton
Lightfoot
Waller
Kingsmill
Skiffes Creek
Hayes
Yorktown
Dow
Surry
Peninsula
Whealton
Winchester
Newport News
Chuckatuck
Four
230-kV
Suffolk
Yadkin
Chesapeake
Portsmouth
Overloaded Line
Overloaded Transformer
N
S
E
W
0
5
10
20
30
40
Miles
5


Summer 2015
Proposed
Project
Surry - Skiffes Creek 500 kV
Skiffes Creek - Whealton 230kV
No Violations
Peninsula
Shellbank
Newport News
Yorktown
Hayes
Skiffes Creek
Whealton
Winchester
Kingsmill
Dow
Lightfoot
Waller
Surry
Chuckatuck
Suffolk
Yadkin
Lanexa
Chickahominy
Gloucester
Mathews
New Kent
Charles City
Prince George
Sussex
Southampton
Henrico
Chesterfield
Colonial Heights
Petersburg
Isle of Wight
James City
Williamsburg
Franklin City
Chesapeake
Portsmouth
Norfolk
Hampton
Newport News
Four
230-kV
lines
6
N
E
S
W
0
5
10
20
30
40
Miles


Summer 2015
Alternative A
Hybrid Single Circuit 230kV UG
Violations:
Line #2113 (Lanexa-Waller)
Suffolk 500-230 kV Tx
230kV UG Line #1 (Surry-Skiffes)
Line #209 (Skiffes-Yorktown)
Chickahominy
Lanexa
Lightfoot
Waller
Kingsmill
Skiffes Creek
Dow
Surry
Hayes
Yorktown
Peninsula
Shellbank
Whealton
Winchester
Newport News
Chuckatuck
Suffolk
Yadkin
Four 230-kV lines
Gloucester
Mathews
New Kent
Charles City
James City
Henrico
Chesterfield
Colonial Heights
Petersburg
Prince George
Surry
Sussex
Isle of Wight
Southampton
Franklin City
Chesapeake
Portsmouth
Norfolk
Hampton
Overloaded Line
Overloaded Transformer
0 5 10 20 30 40 Miles
N E S W
7


Summer 2015
Alternative B
Hybrid Double-Circuit 230kV UG
Violations:
Suffolk 500-230 kV Tx
Line #209 (Skiffes-Yorktown)
Overloaded Line
Overloaded Transformer
Chickahominy
Lanexa
Lightfoot
Waller
Kingsmill
Skiffes Creek
Dow
Surry
Hayes
Yorktown
Peninsula
Shellbank
Newport News
Whealton
Winchester
Chuckatuck
Suffolk
Yadkin
0
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Miles
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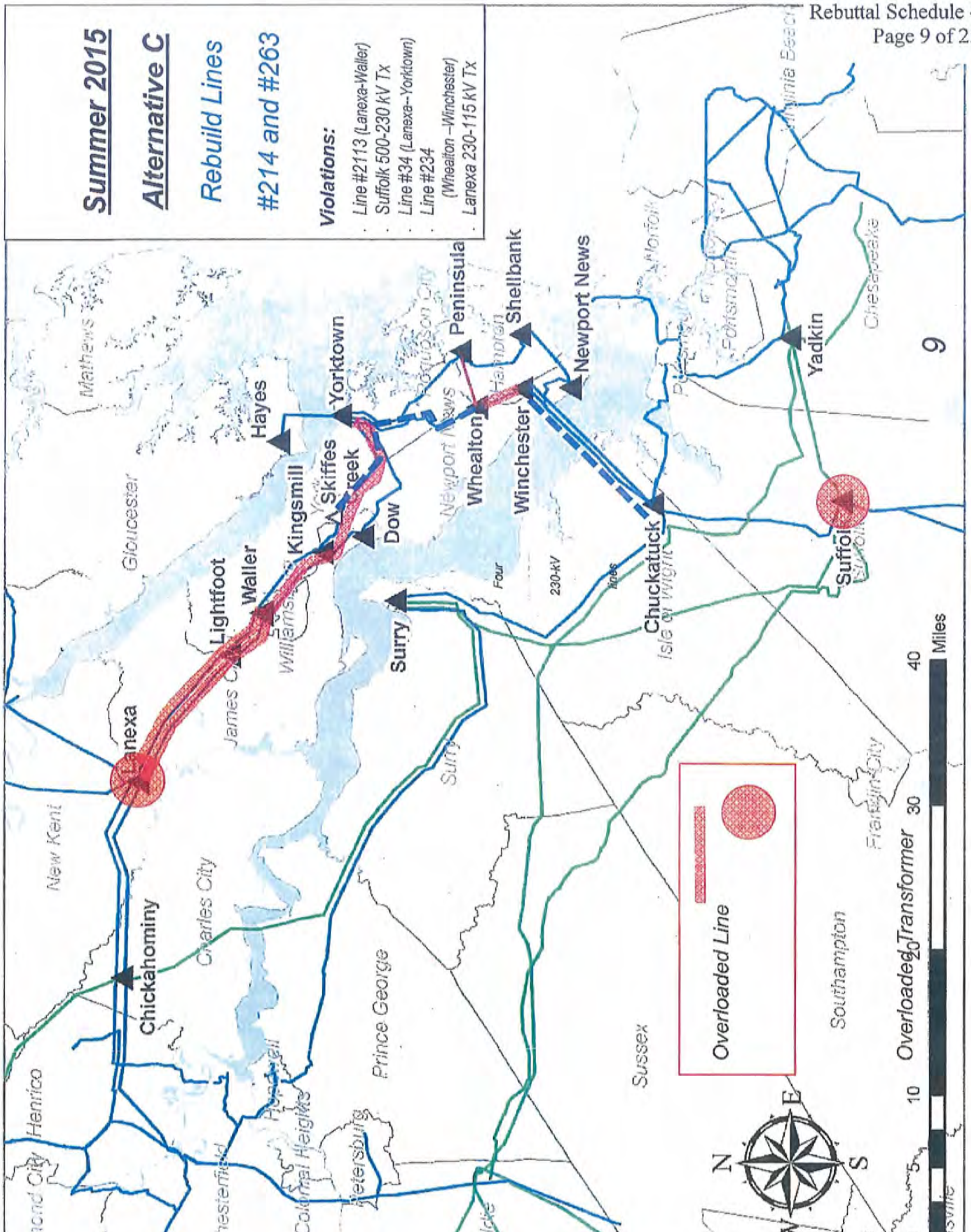
Summer 2015
Alternative C
Rebuild Lines
#214 and #263
Violations:
Line #2113 (Lanexa-Waller)
Suffolk 500-230 kV Tx
Line #34 (Lanexa–Yorktown)
Line #234
(Whealton –Winchester)
Lanexa 230-115 kV Tx
Overloaded Line
Overloaded Transformer
Chickahominy
Lightfoot
Waller
Kingsmill
Skiffes
Dow
Hayes
Yorktown
Peninsula
Shellbank
Newport News
Whealton
Winchester
Chuckatuck
Surry
Yadkin
Suffolk
Gloucester
Mathews
New Kent
Charles City
Prince George
Sussex
Southampton
Henrico
Chesterfield
Petersburg
Colonial Heights
Isle of Wight
James City
Williamsburg
Chesapeake
Portsmouth
Norfolk
Hampton
Franklin City
Miles
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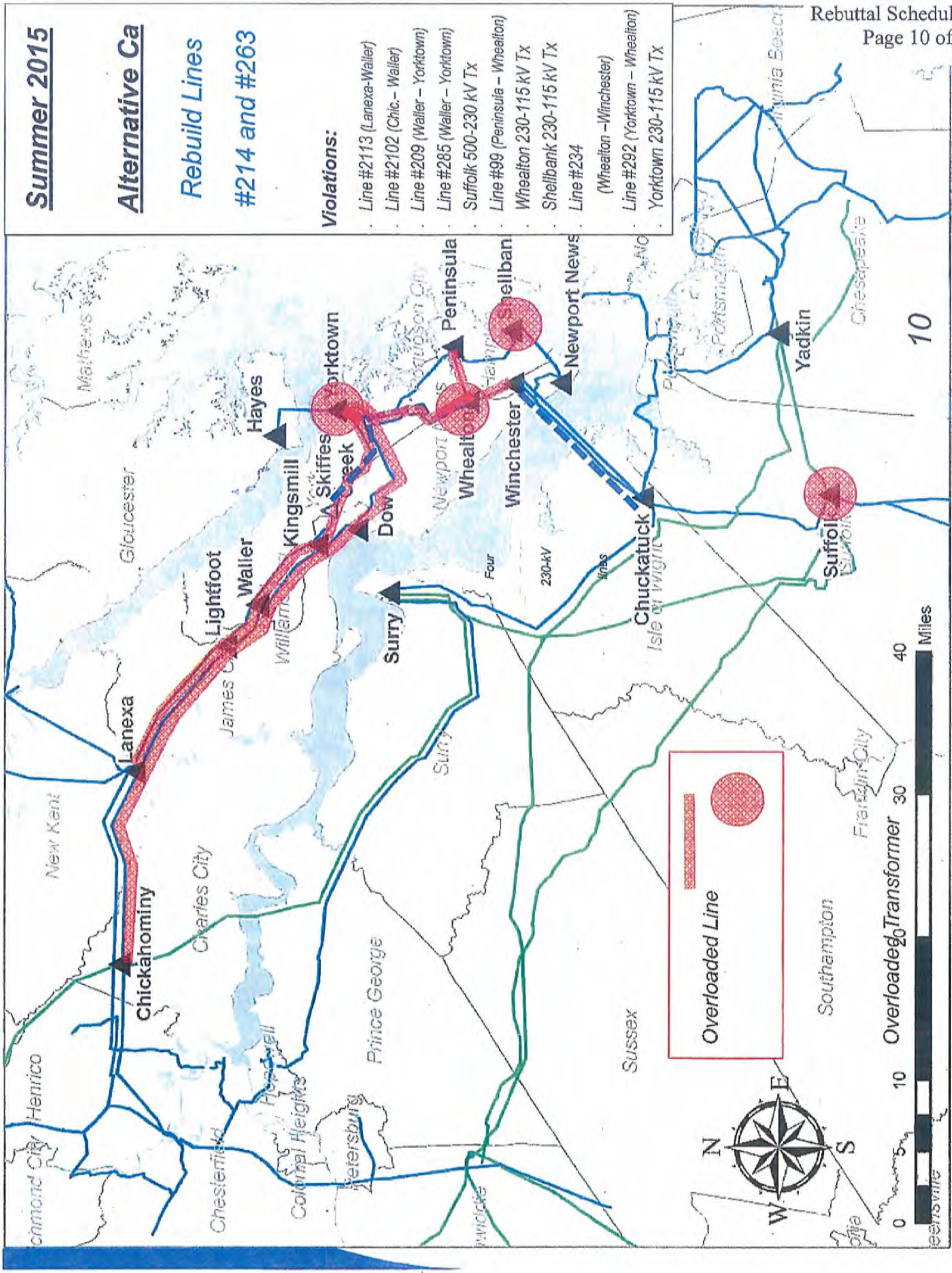
Summer 2015
Alternative Ca
Rebuild Lines
#214 and #263
Violations:
Line #2113 (Lanexa-Waller)
Line #2102 (Chic.- Waller)
Line #209 (Waller – Yorktown)
Line #285 (Waller - Yorktown)
Suffolk 500-230 kV Tx
Line #99 (Peninsula – Whealton)
Whealton 230-115 kV Tx
Shellbank 230-115 kV Tx
Line #234
(Whealton –Winchester)
Line #292 (Yorktown – Whealton)
Yorktown 230-115 kV Tx
Chickahominy
Lanexa
Lightfoot
Waller
Kingsmill
Skiffes
Dow
Hayes
Peninsula
Newport News
Winchester
Chuckatuck
Surry
Yadkin
Overloaded Line
Overloaded Transformer
Miles
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N
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W
Gloucester
New Kent
Charles City
Prince George
Sussex
Southampton
Henrico
Chesterfield
Colonial Heights
Petersburg
Chesapeake
Portsmouth
Suffolk
Isle of Wight

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Line # 2113 (Lanexa-Waller)	Yes	Yes		Yes	Yes	
Line 2102 (Chickahominy – Waller)	Yes			Yes	Yes	
Line #214 (Surry – Winchester)	Yes					
Line #263 (Chuckatuk – Newport News)	Yes					
Line #209 (Waller-Yorktown)	Yes			Yes	Yes	
Line #285 (Waller- Yorktown)	Yes				Yes	
Suffolk 500-230 kV Tx	Yes	Yes	Yes	Yes	Yes	
230 kV UG Line #1 (Surry - Skiffes)		Yes				

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Dominion

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Line # 34 (Lanexa--Yorktown)	Yes			Yes		
Line # 58 (Lanexa--Yorktown)	Yes			Yes		
Line #209(Skiffes – Yorktown)		Yes	Yes			
Line #34(Skiffes –Yorktown)			Yes			
Line #99 (Peninsula – Whealton)	Yes			Yes	Yes	Yes
Whealton 230-115 kV Tx	Yes	Yes	Yes	Yes	Yes	
Shellbank 230-115 kV Tx	Yes			Yes	Yes	
Line #234 (Whealton –Winchesters)	Yes			Yes	Yes	
Line #261(Newport News – Shellbank)	Yes					

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Chickahominy 500-230 kV Tx	Yes					
Lanexa 230-115 kV Tx	Yes			Yes		
Line #292 (Yorktown – Whealton)	Yes				Yes	
Line #289 (Chuckatuk – Suffolk)	Yes					
Line #2076 (Birchwood – Northern Neck)	Yes					
Yorktown 230-115 kV Tx					Yes	
Skiffes Creek 230 kV SVC				Yes		

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Dominion

Basecase: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	1	No CSC	0	39	350	21
2015	2	SU2	0	62	N/A	N/A
2015	5	SU1	1	93	N/A	N/A
2021	8	No CSC	0	55	559	43
2021	9	SU2	0	49	N/A	N/A
2021	12	SU1	0	184	N/A	N/A

Dominion

Proposed Project: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	3	No CSC	0	0	0	0
2015	4	SU2	0	0	N/A	N/A
2021	10	No CSC	0	0	2	0
2021	11	SU2	0	0	N/A	N/A

Dominion

Alternative A: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6A	No CSC	0	0	9	3
2015	7A	SU1	0	3	N/A	N/A
2021	13A	No CSC	0	9	113	7
2021	14A	SU1	0	1	N/A	N/A

Dominion

Alternative B: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6B	No CSC	0	1	4	0
2015	7B	SU1	0	2	N/A	N/A
2021	13B	No CSC	0	1	12	0
2021	14B	SU1	0	0	N/A	N/A

Alternative C: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6C	No CSC	0	5	122	8
2015	7C	SU1	0	70	N/A	N/A
2021	13C	No CSC	0	12	182	13
2021	14C	SU1	0	39	N/A	N/A

Dominion

Alternative Ca – Rebuild of Line #214 and #263 (Open L 34 & 58 System Reconfiguration): Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6Ca	No CSC	0	3	84	8
2015	7Ca	SU1	0	5	N/A	N/A
2021	13Ca	No CSC	0	10	149	13
2021	14Ca	SU1	0	4	N/A	N/A

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 4
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Dominion

230 kV Alternative A + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17A	No CSC	0	0	0	0
2015	18A	SU1	0	0	N/A	N/A
2021	21A	No CSC	0	0	0	0
2021	22A	SU1	0	0	N/A	N/A

Alternative requires 1,008 MW in 2015 and 1,449 MW (2 units min, 1 unit ≥ 87 MW) in 2021

Dominion

230 kV Alternative B + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17B	No CSC	0	0	0	0
2015	18B	SU1	0	0	N/A	N/A
2021	21B	No CSC	0	0	0	0
2021	22B	SU1	0	0	N/A	N/A

Alternative requires 159 MW in 2015 and 551 MW (2 units min, 1 unit ≥ 27 MW) in 2021

Dominion

230 kV Alternative C + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17C	No CSC	0	0	0	0
2015	18C	SU1	0	0	N/A	N/A
2021	21C	No CSC	0	0	0	0
2021	22C	SU1	0	0	N/A	N/A

Alternative requires 552 MW (2 units min, 1 unit ≥ 56 MW) in 2015 and 505 MW (2 units min, 1 unit ≥ 139 MW) in 2021

Dominion

Stand-Alone Generation Option: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	15	No CSC	0	0	0	0
2015	16	SU1	0	0	N/A	N/A
2021	19	No CSC	0	0	0	0
2021	20	SU1	0	0	N/A	N/A

Alternative requires 620 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2015 and 620 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2021

Dominion

Proposed Project Without Retirements: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2021	23	No CSC	0	0	2	11
2021	24	SU2	0	4	N/A	N/A
2021	25	No CSC	0	0	0	0
2021	26	SU2	0	0	N/A	N/A

Dominion®

CASE NO. PUE-2012-00029
COMPARISON OF ELECTRICAL ALTERNATIVES
($ Millions in 2012 Dollars)

			Alternative A 230 kV[1]		Alternative B 230 kV[2]		Alternative C 230 kV[3]		
2015	Proposed 500 kV	Alternative 500 kV	Transmission Only	Transmission Plus Generation	Transmission Only	Transmission Plus Generation	Transmission Only[5]	Transmission Plus Generation	Stand-Alone Option[4]
Surry-Skiffes Creek Line	61.1	115.5	187.5	187.5	343.8	343.8	N/A	N/A	N/A
Skiffes Station	43.8	43.8	23.5	23.5	24.8	24.8	N/A	N/A	N/A
Surry Station/Chickahominy Station	1.7	5.0	14.0	14.0	23.0	23.0	N/A	N/A	N/A
Skiffes Creek-Whealton Line	46.4	46.4	46.4	46.4	46.4	46.4	N/A	N/A	N/A
Whealton Substation	2.0	2.0	2.0	2.0	2.0	2.0	N/A	N/A	N/A
Other Substations	0.4	0.5	0.4	0.4	0.4	0.4	N/A	N/A	N/A
Generation Cost	N/A	N/A	N/A	350.0	N/A	100.0	N/A	350.0	633.0
Cost Subtotal	155.4	213.2	273.8	623.8	440.4	540.4	144.8	494.8	633.0
Additional Cost for Full Compliance	0.0	0.0	214.8	0.0	48.2	0.0	82.1	0.0	0.0
Total Cost	**155.4**	**213.2**	**488.6**	**623.8**	**488.6**	**540.4**	**226.9**	**494.8**	**633.0**
2021	Proposed 500 kV	Alternative 500 kV	Transmission Only	Transmission Plus Generation	Transmission Only	Transmission Plus Generation	Transmission Only[5]	Transmission Plus Generation	Stand-Alone YT Generation
Additional Cost for Full Compliance	17.3	17.3	26.7	577.0	26.7	577.0	181.9	577.0	712.0
Total Cost	**172.7**	**230.5**	**515.3**	**1,200.8**	**515.3**	**1,117.4**	**408.8**	**1,071.8**	**1,345.0**

Notes

1. Alt. A: underground 230 kV hybrid single circuit (1000 MVA) on James River Crossing Variation 3 Hybrid Conceptual Route.
2. Alt. B: underground 230 kV hybrid double circuit (1000 MVA/circuit) on James River Crossing Variation 3 Hybrid Conceptual Route.
3. Alt. C: rebuild of the existing James River crossing of 230 kV Line #214 and 230 kV Line #263.
4. Amount of generation at Yorktown that is the "lowest" cost to solve the need. 620 MW in 2015 and 2021 (2 units minimum; lose 1 unit and maintain ≥ 295 MW).
5. Alternative C is not constructable without generation already in place to address reliability issues that result from the wreck and rebuild of existing lines.
   - Generation required to be in place to support construction would cost between $383M - $652M.
   - To construct the facilities needed to address NERC Reliability Violations in 2015 would take 10 years. Additional construction time would be needed to address 2021 NERC Reliability Violations.

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following response to Question No. 23 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Peter Nedwick
Consulting Engineer Electric Transmission Planning
Virginia Electric and Power Company

Question No. 23:

For the proposed Surry - Skiffes Creek line and the seven transmission alternatives identified in Section I.C of the Appendix to the Company's Application, please identify the PJM regional cost allocators applicable to each, including any PJM socialization.

Response:

In accordance with its Tariff Requirements, PJM has proposed to the Federal Energy Regulatory Commission ("FERC") the cost allocations shown in the table below for: (a) the Surry to Skiffes Creek 500 kV Line, (b) the Skiffes Creek 500-230-115 kV Switching Station, and (c) the Skiffes Creek to Whealton 230 kV Line.

See Page 110 of the Appendix for a copy of the pertinent information also shown below. While the current PJM socialization allocator is 12.38% for the Dominion Zone, the socialization allocators typically change each year when PJM updates them for each calendar year to reflect changes in each transmission zone's annual peak load from the 12-month period ending October 31 of the year proceeding the year for which the annual cost responsibility allocation is determined. The annual peak loads used to determine the 12.38% were based on 2011 annual peak loads. Additionally, it should be noted that the current socialization allocation method is subject to rehearing by the FERC in Docket No. EL05-121 and is subject to refund.

With respect to the allocations described below regarding the alternatives, the Company is using PJM's proposed allocations for the 500 kV and the <500 kV portions of the Skiffes Creek project as proxies since power flow based cost allocation calculations are prepared by PJM and have not been made available for the alternatives. Also, with respect to these alternatives, it should be noted that PJM's Board of Managers ("Board") has not approved those specific configurations. If further Board approval is required to implement an alternative and if such approval is not received before February 1, 2013, the alternative would be subject to the modified PJM cost allocation methods filed by the PJM transmission owners in FERC Docket No. ER13-90 for compliance with FERC Order No. 1000, if FERC approves their filing. If an alternative that includes some 500 kV facilities becomes subject to the proposed modified cost allocations then the proposed allocations would socialize 50% of the costs of the 500 kV portion of the alternative and the remaining 50% as well as the <500 kV portion of the alternative would be allocated based on the results from a power flow study that assigns costs to each zone based on each zone's projected relative use of a proposed facility. If one of the <500 kV alternatives becomes subject to the proposed cost allocations, then the costs of that project will be allocated based on the results from a power flow study that assigns costs to each zone based on each zone's projected relative use of a proposed facility. Because the FERC has not issued an order accepting this filing, the Company cannot predict if or when the modified allocation methods in the filing will become effective.

b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)	AEC - 1.83%, AEP - 15.12%, APS - 5.53%, ATSI - 8.65%, BGE - 4.46%, ComEd - 14.64%, ConEd - 0.55%, Dayton - 2.21%, DL - 1.85%, DPL - 2.61%, Dominion - 12.88%, ECP - 0.19%, JCPL - 4.07%, ME - 1.92%, Neptune - 0.41%, PECO - 5.54%, PENELEC - 1.93%, PEPCO - 4.33%, PPL - 4.77%, PSEG - 6.74%, RE - 0.27%,	6/1/2015
b1905.2	Surry 500 kV Station Work	AEC - 1.83%, AEP - 15.12%, APS - 5.53%, ATSI - 8.85%, BGE - 4.46%, ComEd - 14.64%, ConEd - 0.55%, Dayton - 2.21%, DL - 1.85%, DPL - 2.61%, Dominion - 12.38%, ECP - 0.19%, JCPL - 4.07%, ME - 1.92%, Neptune - 0.41%, PECO - 5.54%, PENELEC - 1.93%, PEPCO - 4.33%, PPL - 4.77%, PSEG - 6.74%, RE - 0.27%,	6/1/2015
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2015
b1905.4	New Skiffes Creek - Whealton 230 kV line	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016
b1905.5	Whealton 230 kV breakers	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016
b1905.6	Yorktown 230 kV work	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016
b1905.7	Lanexa 115 kV work	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016
b1905.8	Surry 230 kV work	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016
b1905.9	Kings Mill, Peninmen, Toano, Waller, Warwick	Dominion - 99.84%, PEPCO - 0.16%,	6/1/2016

<u>For Alternative 1 – Surry to Skiffes Creek double circuit 230 kV Line</u>
The following cost allocation would apply to the entire project: Dominion 99.84% and PEPCO 0.16% based on PJM's current cost allocation methodologies.

<u>For Alternative 2 - Chickahominy to Skiffes Creek double circuit 230 kV Line</u>
The following cost allocation would apply to the entire project: Dominion 99.84% and PEPCO 0.16% based on PJM's current cost allocation methodologies.

For Alternative 3 - Chickahominy to Skiffes Creek 500 kV Line through Lanexa Substation
For all the 230 kV and 115 kV associated components, including the 500-230 kV transformers the following cost allocation would apply: Dominion 99.84% and PEPCO 0.16% based on PJM's current cost allocation methodologies. The 500 kV Line construction costs and the 500 kV substation work at Chickahominy would be based on the same percentages as shown in b1905.1 and b1905.2 above respectively.

For Alternative 4 – Construct a 500 kV Underground Line
The same cost allocation as proposed for the overhead option would apply. For the Surry 230 kV double underground circuit option the entire project would be expected to be allocated in the following manner: Dominion 99.84% and PEPCO 0.16% based on PJM's current cost allocation methodologies.

For Alternative 5 – 500 kV Line: Chickahominy – Skiffes Creek vs Surry – Skiffes Creek The 500 kV Line and associated 500 kV Substation work (Excluding the 500 -230 kV Transformers)
The cost would be allocated in the same manner as the proposed project b1905.1 and b1905.2 as shown above in the cost allocation table.

For Alternative 6 – Surry 230 kV Partial Alternative
Since it consists of only 230 kV and 115 V transmission facilities, the entire project would be cost allocated in the following manner: Dominion 99.84% and PEPCO 0.16% based on PJM's current cost allocation methodologies.

For Alternative 7 – Great Bridge and Surry 230 kV Alternative
The Company would anticipate that this project would be allocated 100% to Dominion based on the current cost allocation of the Suffolk-Yadkin 230 kV Line which is tied to generation retirements in the Chesapeake area.

POWER FLOW CASE TIMELINE

Dec 2010	Jan - March 2011	Sept 2011	Nov 2011	Dec 2011	Dec 2011 - April 2012	April 2012 - May 2012
FAC -008 Dec 2010 In effect Category C&D Analysis based on 130% of rateC	Analysis of LTP EHV Projects need based on Sum2019(2010LF) Sum 2020 (2011 LF) **Skiffes Creek ISD 2019**	Va & NC IRP Filed Indicate Generation Retirements	York 1, CEC 1-4 Retirements filed wth PJM	FAC-008 Updated With CIP Recommendation on Rate C to be used in Category C & D Analysis	PJM & DVP Generation Retirement Study S2015 & S2016 based on 2011 LF **Skiffes Creek ISD 2015**	DVP updated need analysis for SCC Application S2015, 2016 & 2021 based on 2012 LF **Skiffes Creek ISD 2015**

June 2012	Oct 2012	Oct 2012	Dec 2012	Jan 2013	Feb 2013
Application filed w Va SCC PUE-2012-00029	Staff asks for Skiffes Creek Project to be modeled in Sum2019(2010LF) Sum 2020 (2011 LF) Power Flow Cases Question 2-16 (Creates Power flow cases DVP never used for the need analysis of the Skiffes Creek project)	York 2 retirement filed with PJM, CEC 3 & 4 Retirement accelerated filed wth PJM	FAC-008 Updated Light Load Criteria added	Staff review of 2015, 2106, 2019, 2020 and 2021 power flow cases confirms reliability violations and Skiffes Creek Project resolves these reliability violations	Updated DVP need analysis for S2015, 2016 & 2021 based on 2013 LF confirms **Skiffes Creek ISD 2015**

EXHIBIT A

PLANNING GUIDELINES

GENERAL CRITERIA

The Company endeavors to maintain a high degree of reliability in electric service that satisfies the average customer's service requirements at a reasonable cost.

The North American Electric Reliability Corporation (NERC) and the eight (8) regional reliability councils have developed mandatory, enforceable NERC Reliability Standards which must be complied with to assure reliable service to all areas of the United States. Additional criteria may be needed within an operating system to satisfy specific operating requirements unique to that area.

The Company is a member of the SERC Reliability Corporation (SERC) and is guided by the criteria set forth by that council. In addition, the following criteria are used in planning the Company's transmission system. These criteria apply to conditions of expected firm power transfers among the Company and its neighboring power systems and to the official company load forecasts, which are based on "normal" weather and projected, prevailing economic conditions.

As with generating capacity, reserve capacity must also be provided in the transmission system to recognize the effects of deviations from normal weather, load forecast uncertainty and variations in day to day operating conditions. In the application of the following criteria an allowance of 6% should be made in transmission facility loading (lines and transformers).

- Under normal loading conditions (All transmission facilities in service) no transmission facility should be loaded greater than its normal rating.

- The loss of any one transmission circuit should not cause the emergency rating(8 hour) to be exceeded on any of the remaining transmission facilities nor should it cause the loss of any load, other than the load connected to that circuit, and the resultant voltage at any location on the 115 kV and 138 kV transmission system should not drop below 0.93 P.U. after transformer load tap changing equipment has readjusted nor should it drop below 0.93 P.U. on the 230 kV system and 1.01 P.U. on the 500 kV system.

- The loss of any two transmission circuits on a common right-of-way should not result in cascading outages or loss of load, other than that connected to the two circuits, and the resultant voltage at any location on the transmission system should not drop below 0.92 P.U. after transformer load tap changing equipment has readjusted nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overload to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The transmission system should be capable of supplying peak loads without exceeding the emergency rating(8 hour rating) on any facility for the following:

  1. The outage of the two largest generators in any generating station when all transmission facilities are in service.
  2. Critical System Conditions (The outage of the largest generator in any generating station which has the greatest effect on the transmission facilities being studied.) and the loss of any transmission facility.

During the above generation outages, other Company generating sources would be adjusted to make up the deficiency to the limit of available capacity.

- Stability requirements described in Table I of NERC Reliability Standards TPL-001-0 through TPL-004-0 must be met, at a minimum.

- The loss of three or more transmission circuits on a common right-of-way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right-of-way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

- The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The loss of a generating station substation, switching station or load substation should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The outage of a critical transmission facility, which occurs while another critical transmission facility is already out of service, should not result in cascading outages or intolerably low voltage (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The transmission system should be capable of transferring reasonable amounts of power, in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities with all transmission facilities in service or with one transmission circuit or transformer out of service and not exceed the maximum continuous rating of any remaining transmission facility. Any new facilities connected to the transmission system (greater than 20 MW) should not significantly decrement (greater than 5%) FCITC's for transfers between utilities.

- Combustion turbine generators should not be used for more than seven days to provide adequate service during the outage of a line or transformer. The assumed availability of combustion turbine generator units at any one time shall be in accordance with the following guide:

Number of Units At The Location	Number Available At Any One Time
2	1
3	2 smallest
4	3 smallest
5	3 smallest
6	4 smallest
Above 6	70% of Total Capacity

- Load on transmission radial lines without alternate supply should be limited to approximately 100 MW. A key factor in evaluating the load limitation on a radial transmission line is the distribution load that can be switched to circuits served from other sources. Unlike load served from a networked transmission line where a downed conductor or structure can be sectionalized allowing the remainder of the line to be reenergized before repairs are completed, load served from a radial transmission line cannot be reenergized until all repairs to the line are completed.

Other factors include being able to perform maintenance on the radial line, outage history of line, load density and type, tie capability, etc.

- The transmission system must be examined frequently to assure that an effectively grounded system is maintained. A bus is considered to be "effectively grounded" when the following relationships are true:
    - $X_o/X_1 \leq 3$
    - $R_o/X_1 \leq 1$

This relationship assumes $R_1/X_1 = 0$, which is a worst case condition. If one or both of these relationships are not true, the effective grounding should be checked more precisely by referring to the curves found in the "*ABB Electrical Transmission and Distribution Reference Book*". The curves can be found in Chapter 18, page 626. The proper curve to use should be based on the actual R_1/X_1 ratio. Any set of ratios lying below the appropriate curve marked 80% will provide effective grounding for 80% of the standard lightning arresters used on the Dominion system.

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 26 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on November 14, 2012 has been prepared under my supervision.

Peter Nedwick
Consulting Engineer Electric Transmission Planning
Virginia Electric and Power Company

Question No 26:

In discussing the Surry-Skiffes Creek Double Circuit 230 kV transmission line alternative considered by the Company (Alternative No. 1), Page 56 of the Appendix states that "[t]his alternative would not resolve all of the identified NERC criteria violations." Page 17 of Company witness Nedwick's direct testimony includes a similar statement.

(a) Please identify specifically all NERC criteria violations that this alternative would not resolve.

(b) For each violation identified in (a), please provide the data supporting the Company's conclusion that such violation(s) would not be resolved by the referenced alternative. The response is expected to include, but not to be limited to, the following:

(b1) all reports (in workable electronic format) associated with studies conducted by DVP and PJM, along with the native versions of all study spreadsheets and additional documents reflecting the data input and output results (*i.e.*, appendices, diagrams, etc.);

(b2) the electronic models in electronic PSS/E v32 used by DVP and PJM to conduct the studies at (b1);

(b3) the PSS/E definition files (.sub, .mon, .con, and .thr) associated with contingencies simulated during the study process;

(b4) the PSS/E IDEV files (in PSS/E v32 format) for the analyzed Surry-Skiffes Creek Double Circuit 230 kV transmission line alternative and any other changes made to the original Base Case models; and

(b5) additional PSS/E files necessary to replicate the outcome of the relevant DVP and PJM studies.

Response:

a. For Summer 2016, the Skiffes Creek to Yorktown 230 kV Line would be overloaded for two different contingency conditions: The first is an outage of the Chuckatuck to Benns Church 230 kV Line followed by an outage of the Denbigh to Skiffes Creek 230 kV Line; and the second is an outage of the Denbigh to Skiffes Creek 230 kV Line followed by an outage of the Skiffes Creek to Warwick 230 kV Line.

   Also for Summer 2016 the Suffolk 500-230 kV transformer ("Tx") #2 would be overloaded for the following contingency condition: an outage of the Septa-Yadkin 500 kV Line followed by an outage of the Suffolk to Yadkin 500 kV Line.

   For Summer 2021, the Skiffes Creek to Yorktown-230 kV Line would be overloaded for three different contingency conditions: The first is an outage of the Chuckatuck to Benns Church 230 kV Line followed by an outage of the Denbigh to Skiffes Creek 230 kV Line; the second is an outage of the Denbigh to Skiffes Creek 230 kV Line followed by an outage of the Skiffes Creek to Warwick 230 kV Line; and the third is an outage of the Newport News to Benns Church 230 kV Line followed by an outage of the Denbigh to Skiffes Creek 230 kV Line.

   The Skiffes Creek to Fort Eustis 115 kV Line would be overloaded for an outage of the Yorktown 230-115 kV Tx followed by an outage of the Skiffes Creek to Yorktown Naval Weapons Center 115 kV Line.

   Also for Summer 2021, the Suffolk 500-230 kV Tx #1 and #2 would be overloaded for the following contingency condition: an outage of the Septa-Yadkin 500 kV Line followed by an outage of the Suffolk to Yadkin 500 kV Line.

b. (1) See Attachment Staff Set 3-26(b)(1), which contains the results of the Contingency Analysis (MUST) for Summer 2016 and Summer 2021 described in the Company's response to Staff Set 3-26(a).

   (2) See Confidential Attachment Staff Set 3-26(b)(2), which contains Critical Energy Infrastructure Information:

      Summer 2016 _Base_noyork2_Surry230kvopta.sav

      Summer 2021 _base_optionSurry230kv.sav

   (3) See Attachment Staff Set 3-26(b)(3), which contains peninsula.sub, vapsys.mon and the peninsula.con files used for this analysis.

(4) The Surry to Skiffes Creek double circuit 230 kV Line was manually entered into the case. No idv was created. This case was created by removing from service the Surry to Skiffes Creek 500 kV Line and Skiffes Creek 500-230 kV Tx(s) and entering the impedance and rating for two 230 kV lines between Surry 230 kV and Skiffes Creek 230 kV busses.

(5) None.

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 27 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on November 14, 2012 has been prepared under my supervision.

Peter Nedwick
Peter Nedwick
Consulting Engineer Electric Transmission Planning
Virginia Electric and Power Company

Question No 27:

In discussing the Underground Surry-Skiffes Creek Double Circuit 230 kV transmission line alternative considered by the Company (part of Alternative No. 4), Page 57 of the Appendix states that "[a]n underground 230 kV line from Surry to Skiffes Creek would have the same electric deficiencies as Alternative No. 1, including failure to resolve all of the identified NERC criteria violations...." Page 20 of Company witness Nedwick's direct testimony includes a similar statement.

(a) Please identify specifically all NERC criteria violations that this alternative would fail to resolve.

(b) For each violation identified in (a), please provide the data supporting the Company's conclusion that the referenced alternative would fail to resolve such violation(s). The response is expected to include, but not to be limited to, the following:

(b1) all reports (in workable electronic format) associated with studies conducted by DVP and PJM, along with the native versions of all study spreadsheets and additional documents reflecting the data input and output results (*i.e.*, appendices, diagrams, etc.);

(b2) the electronic models in electronic PSS/E v32 used by DVP and PJM to conduct the studies at (b1);

(b3) the PSS/E definition files (.sub, .mon, .con, and .thr) associated with contingencies simulated during the study process;

(b4) the PSS/E IDEV files (in PSS/E v32 format) for the analyzed Surry-Skiffes Creek Double Circuit 230 kV underground transmission line alternative and any other changes made to the original Base Case models; and (b5) additional PSS/E files necessary to replicate the outcome of the relevant DVP and PJM studies.

Response:

The electrical parameters to determine the actual resistance, reactance and charging current for a 230 kV underground option are not known at this time, because manufacture specifications are not known. Therefore, the 230 kV overhead option served as the proxy for the underground option since either option would require the same MVA Capability.

a. See Company's response to Staff Set 3-26(a).

b. (1) See the Company's response to Staff Set 3-26(b)(1).
(2) See the Company's response to Staff Set 3-26(b)(2).
(3) See the Company's response to Staff Set 3-26(b)(3).
(4) See the Company's response to Staff Set 3-26(b)(4).
(5) See the Company's response to Staff Set 3-26(b)(5).

James City County, Virginia
Case No. PUE-2012-00029
Virginia Electric and Power Company
d/b/a Dominion Virginia Power
First Set

Questions Regarding the Whittier Direct Testimony

Question No. 33:

In regards to Table 2 on page 12 of the Whittier Direct Testimony:

a. Provide a listing of each transmission circuit by mileage that is included in the 45 miles of 230 kV overhead rebuild noted in that table.
b. Also noted in Table 2 is an estimate of $36 million for a new 230 kV overhead river crossing of about six miles.
    i. For this new 230 kV overhead river crossing, please indicate what type of 230 kV switching stations would be used for this new 230 kV line and detailed estimates of their construction cost.
    ii. Identify the routing constraints that James City County identified in the construction of this alternative.
    iii. Provide a copy of all power flow cases, studies and reports that were developed when studying the feasibility of this proposed alternative. To the extent that these power flow cases, studies and reports are available electronically, please provide in electronic format with underlying calculations, formulas, links and assumptions intact.

Response:

a. A listing of each transmission circuit by mileage: These distances are approximate, based on scaling from Google Earth images:

Line 263 between Chuckatuck and Newport News excluding river crossing	4 miles
Lines 214 & 234 between Surry and Whealton excluding river crossing	32 miles
Line 261 between Newport News and Shellbank	7 miles
Total	43 miles
Round up	45 miles

b. i. Please indicate what type of 230 kV switching stations would be used: There would not be any new switching stations involved with the upgrades suggested by Mr. Whittier. The one line diagram of the electrical system would look the same as the current system, except for the addition of capacitors. The new river crossing would take the place of one of the existing lines, line 214 or line 263. The two lines on the existing river crossing structures would be bundled into one circuit replacing the other existing line.

James City County, Virginia
Case No. PUE-2012-00029
Virginia Electric and Power Company
d/b/a Dominion Virginia Power
First Set

b. ii. Identify the routing constraints: James City County did not identify any routing constraints for the construction of this alternative. That is beyond the scope of the analysis provided by Mr. Whittier. The intent of Mr. Whittier's testimony was to demonstrate that alternatives to Dominion's proposed project are very likely to be viable, cost competitive and can solve the cited NERC reliability criteria violations especially in the near term and should be investigated further by Dominion and the Commission.

b. iii. Provide a copy of all power flow cases, studies and reports: see attached compact disc containing five spreadsheet files saved under the name, "W Whittier Response to question 33.b.iii."

- Results Comparison – This is an Excel spreadsheet that compares criteria violations for the different configurations described below.
- Sum_2019.sav – This is the PSSE case of the existing system at a 2019 load level as provided by Dominion in response to Staff Set 1-3(b)(i)(ii).
- Sum_2019_GensOff.sav – This is a PSSE case based on case Sum_2019.sav but modified to turn off all Yorktown and Chesapeake generators. This is the new base case.
- Sum_2019_GensOff_DCTMod.sav – This is a PSSE case based on case Sum_2019_GensOff.sav but modified with the addition of a new river crossing to eliminate the double circuit tower issue. Line 263 was duplicated to create a parallel Line 263 and Line 214 has higher ratings (line impedance and ratings were modeled after a similar 230kV line from "CRITTDN" to "SURRY").
- Sum_2019_GensOff_DCTMod_PennCap.sav – This is a PSSE case based on case Sum_2019_GensOff_DCTMod.sav but with the addition of a capacitor at Penninsula (the same as the one at another local bus, "6CHCKA_1") to mitigate low voltages.

The "Results Comparison" file includes three tabs. The "DNS" tab shows that the double circuit tower modifications solved the "did not solve" case that occurred for the new base case. The "Therm" tab shows, in column L, that the double circuit tower modifications solved thermal overloads. Note that the overloads that show up for Lines 214 and 263 are corrected by the suggested rebuild or reconductoring of those lines. The "Volt" tab shows that most voltage violations are corrected by the placement of a large capacitor at Penninsula substation. The remaining voltage violations shown in column I are relatively minor and RLC Engineering believes that they can be corrected with some adjustments to the size and location of capacitor additions. Dominion and the Commission should investigate this further.

Respondent:

Waine P. Whittier, PE
Counsel

James City County, Virginia
Case No. PUE-2012-00029
Virginia Electric and Power Company
d/b/a Dominion Virginia Power
First Set

Questions Regarding the Whittier Direct Testimony

Question No. 34:

On pages 4-5 of the Whittier Direct Testimony, the following answer is provided:

> Yes. However, given the extensive amount of highly technical information that needed to be analyzed and the short deadline for filing this testimony, I could not undertake comprehensive powerflow modeling or some other independent analysis that could have provided additional conclusions and potentially additional viable alternative routes.

a. Subsequent to filing the Whittier Direct Testimony, has Mr. Whittier conducted any such analysis?
b. If yes, please provide a copy of all power flow analysis study results, power flow base cases and workpapers to support such analysis. To the extent that these results, cases and workpapers are available electronically, please provide in electronic format with underlying calculations, formulas, links and assumptions intact.
c. If no, please explain why not.

Response:

Mr. Whittier has not undertaken any additional analysis subsequent to the filing.

Respondent:

Waine P. Whittier, PE
Counsel

James City County, Virginia
Case No. PUE-2012-00029
Virginia Electric and Power Company
d/b/a Dominion Virginia Power
First Set

Questions Regarding the Whittier Direct Testimony

Question No. 35:

On page 7 of the Whittier Direct Testimony, he states: "I have not been able to fully analyze each of these alternatives."

a. Subsequent to filing the Whittier Direct Testimony, has Mr. Whittier completed any such analysis?
b. If yes, please provide the results of this analysis and workpapers that supported this analysis. To the extent that these results and workpapers are available electronically, please provide in electronic format with underlying calculations, formulas, links and assumptions intact.
c. If no, please explain why not.

Response:

Mr. Whittier has not performed any additional analysis since his Direct Testimony was filed.

Respondent:

Waine P. Whittier, PE
Counsel

Herling

REBUTTAL TESTIMONY
OF
STEVEN R. HERLING
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, position, place of employment and business address.

A. My name is Steven R. Herling. I am the Vice President of Planning for PJM Interconnection, L.L.C. ("PJM"). My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497.

Q. What are your responsibilities at PJM?

A. As PJM's Vice President of Planning, I am responsible for the Resource Adequacy Planning Department, which develops the long-term load forecast for the PJM region and, in consultation with load-serving entities ("LSEs"), sets and enforces requirements for the sufficiency, adequacy, and availability of the generation resources needed to ensure reliable service to loads; the Interconnection Projects and Interconnection Analysis Departments, which process requests for and evaluate interconnections to the transmission system by new generation and merchant transmission projects; the Interregional Planning Department, which coordinates planning activities with neighboring transmission systems; and the Transmission Planning Department, which evaluates the reliability and market efficiency of the transmission grid and develops the Regional Transmission Expansion Plans ("RTEPs").

Q. Please provide your professional background while at PJM.

A. I have been employed by PJM since May 1990. While at PJM, I have contributed to or led initiatives that resulted in a wide range of milestone achievements in its evolution and growth as a regional transmission organization ("RTO"), including the creation of the RTEP process, the development of procedures and standard terms and conditions for generator and merchant transmission interconnections, and the reliability and adequacy aspects of successive integrations of additional control areas that have more than doubled the size of the PJM market area in the last 10 years.

In addition to my work for PJM, I have contributed to a wide range of activities of the North American Electric Reliability Council ("NERC"), as vice chair of the NERC Planning Committee and on various regional and industry working groups and committees addressing reliability and planning matters.

Q. Please describe your educational and professional credentials.

A. I hold a Bachelor of Science in Electric Power Engineering and a Master of Engineering in Electric Power Engineering, both from Rensselaer Polytechnic Institute. I am a licensed Professional Engineer in the state of Ohio.

Q. Have you previously provided testimony?

A. Yes. I have testified in transmission line Certificate of Public Convenience and Necessity ("CPCN") proceedings in Pennsylvania, West Virginia, Virginia, and New Jersey. I have also testified on a number of occasions on system planning and reliability issues in proceedings before the Federal Energy Regulatory Commission ("FERC"), and various state commissions and legislative task forces.

Q. What is the purpose of your testimony?

A. I have been asked by Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company") to respond to the pre-filed direct testimony of James City County (or "JCC") Witnesses Waine P. Whittier and Robert C. Middaugh regarding PJM's analysis of alternatives related to the proposed Project. In addition, I will respond to concerns raised by James City County regarding the role of demand-side management ("DSM" or "demand response") in the load forecast and transmission planning context. I will also discuss the need for a 500 kV solution to address the reliability need in the North Hampton Roads Load Area and the lack of new generation in the area to offset the need for a new 500 kV transmission source.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, SRH, consisting of Rebuttal Schedules 1-2, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. My rebuttal testimony provides further detail on the RTEP process, including an evaluation of the availability of demand response resources. I also discuss non-incumbent transmission proposals submitted to PJM from LS Power as alternatives to the Company's Project, and explain why the LS Power options are inferior long-term solutions. Lastly, I conclude there is a demonstrated need in the North Hampton Roads Load Area for a new 500 kV source and that the Company's proposed Surry-Skiffes Creek line is the most effective solution.

My testimony is organized as follows:

I. Background on PJM and the RTEP
II. Load Forecast and Demand Response
III. Alternate Transmission Proposals
IV. New and Repowered or Retrofit Generation

I. BACKGROUND ON PJM AND THE RTEP

Q. What is PJM's role in transmission planning and operations?

A. As an RTO, PJM ensures the reliability of the electrical transmission system under its functional control. PJM coordinates the movement of wholesale electricity in the PJM Region, which consists of all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The PJM system serves approximately 51 million customers. PJM dispatches more than 185,000 megawatts ("MW") of generation capacity over more than 65,000 miles of transmission lines – a system that serves approximately 20% of the United States economy. PJM presently has more than 800 members. These members/customers include power generators, transmission owners, electricity distributors, power marketers and large consumers. In its role as an RTO, PJM acts independently and impartially in operating and planning the regional transmission system and in overseeing the wholesale electricity market.

Q. What is the RTEP process and how is it conducted by PJM?

A. As part of its ongoing responsibilities as an RTO, PJM prepares the RTEP each year in order to analyze the electric supply needs of the customers in the PJM Region. PJM evaluates the aggregate needs across its system, identifying potential problems on both a local and regional level. Reliability problems are blind to the boundaries of states or transmission owner service territories. By identifying problems on a regional basis, PJM is able to identify the most effective regional solutions unconstrained by state and transmission owner boundaries. The RTEP directs transmission upgrades to address near-term needs within five years and assesses long-lead time transmission options requiring a planning horizon of 15 years or more. The RTEP provides forward-looking information as to the state of the supply and delivery infrastructure and identifies future system needs, both in terms of reliability and market efficiency. The RTEP will direct PJM's transmission owning members to address such needs through specific transmission solutions. However, the information publicly disseminated through the RTEP permits other resource providers, including generators, demand response providers and merchant transmission developers, the opportunity to address identified system needs in a manner that might delay or even obviate the transmission solution first identified in the RTEP.

Q. You mentioned you have testified in transmission line CPCN proceedings before various state commissions in the past. Please elaborate on your experience before the Virginia State Corporation Commission ("Commission").

A. In 2007 and 2008, I submitted pre-filed direct and rebuttal testimony on behalf of Dominion Virginia Power and testified in the CPCN proceeding before the Commission in which the Company sought approval of a proposed Meadow Brook-Loudoun 500 kV transmission line and related facilities (the "Meadow Brook-Loudoun Line") in Case No. PUE-2007-00031, and the associated proceeding in Case No. PUE-2007-00033. Specifically, I described PJM's RTEP process that determined the need for the Meadow Brook-Loudoun Line in order to resolve the reliability criteria violations identified in that proceeding. The Commission's October 7, 2008 Order approving the Meadow Brook-Loudoun Line validated PJM's RTEP process in that proceeding, and was subsequently upheld on appeal by the Supreme Court of Virginia on November 5, 2009.

II. LOAD FORECAST AND DEMAND RESPONSE

Q. Please describe what resources PJM considers DSM or demand response.

A. There are three categories of demand response products, or DSM, that can participate in PJM's Reliability Pricing Model ("RPM") auctions. These are Limited Demand, Extended Summer Demand, and Annual Demand Resources. While the Extended Summer Demand and Annual Demand Resources may be called to interrupt an unlimited number of times during the summer period and over the entire year, respectively, the majority of the DSM available to PJM operators falls into the Limited Demand Resource product. Limited Demand Resources may only be called upon to interrupt 10 times on weekdays, excluding NERC holidays, during the summer operating period. Each interruption may be called for a maximum duration of six hours with a minimum notice of one or two hours given prior to the interruption.

Q. JCC Witness Whittier claims on page 8 of his testimony that it did not appear that Dominion Virginia Power evaluated DSM measures to help solve reliability violations in the near term. What non-transmission alternatives, including DSM, did PJM consider?

A. Potential non-transmission solutions integrated into planning process need analyses included market-driven additions of new generation capacity, DSM and energy efficiency resources.

Q. How are market-based solution options proposed for consideration in the development of the RTEP?

A. Market-based solutions are developed and integrated into the RTEP process in different ways. Generation and merchant transmission proposals[1] are introduced through the interconnection queue process. DSM and energy efficiency solutions are introduced by participation in PJM's RPM capacity auctions, the market mechanism by which resources, including generation, are committed to PJM operations to ensure the adequacy of the grid. DSM and energy efficiency resources are integrated into the RTEP when they have bid into and cleared an RPM Base Residual Auction ("BRA") or a subsequent Incremental Auction.

However, these resources were not sufficient to resolve the violations of mandatory NERC Reliability Standards ("NERC Reliability Violations" or "Reliability Violations") related to the Yorktown retirements and PJM considers it unlikely that sufficient amounts of these resources can be implemented to offset the need for additional transmission capability into the area. There are currently no generation projects under development in the area and only one 13 MW generator has been placed in service on the Peninsula in recent years. During the 2012 summer peak period, only 13.3 MW of demand resources in the North Hampton Roads Load Area were available to PJM, having committed through previous RPM auctions. In the most recent RPM BRA, Demand Response levels actually began to drop in eastern PJM zones by 10-20% from the previous year, although

[1] Merchant transmission facilities are A.C. or D.C. transmission facilities that are interconnected to the PJM system pursuant to Part IV and Part VI of the PJM Tariff. Merchant transmission facilities are market-based additions to the PJM system which generate revenue streams for the developer through financial rights related, for example, to congestion hedging or the firm withdrawal of energy and capacity from PJM to a neighboring system. Merchant transmission facilities are not specified as required by PJM to resolve transmission needs pursuant to the PJM Operating Agreement, nor are the costs recovered from PJM customers through the schedules of the PJM Tariff.

they increased in the Dominion Zone, but by only 21 MW to a total of 1333 MW for the 2015/16 delivery year.

Q. Of the 1,333 MW of DSM that bid and cleared the 2015/2016 PJM BRA in the Dominion Zone, how much is expected to come from the Hampton Roads Load Area?

A. As discussed earlier, there were only 13.3 MW of DSM resources in the Hampton Roads Load Area during the 2012 summer period. Demand response providers are not required to identify the location of their resources until shortly before the start of each summer operating season. It is, therefore, not possible to predict, at this time, what portion of the 1,333 MW will be located in that area during future years. It would reasonably be expected based on past experience, however, to be a small portion of the total.

Q. You have indicated that PJM does not have the power to compel "Alternative" solutions. Please explain what PJM is authorized to do and not do in this regard.

A. As an RTO, PJM has a defined role in the electric industry. Its primary transmission-related responsibility is to ensure the reliability of the bulk power transmission system. Although PJM has a number of important tools at its disposal – including the ability to direct transmission owners to construct transmission system reinforcements – its powers are not plenary. PJM is not able to direct or otherwise control the siting, capacity, or timing of new generation in high-load areas. PJM is not able to compel or otherwise control the design and implementation of DSM efforts that might, if properly placed and of sufficient dimension, delay or defer the need for transmission reinforcements. PJM can only direct the reinforcement of transmission facilities to address Reliability Violations, either through the modification of existing transmission facilities (which PJM quite frequently directs) or the construction of new transmission facilities.

Q. Are you suggesting that PJM does not consider non-transmission alternatives in evaluating the need for transmission reinforcements?

A. Absolutely not. PJM's planning processes recognize that many of the generation-based and DSM-based alternatives, if targeted, verifiable, and implemented on time and in the right areas of the PJM Region, address identified system reliability issues. As I mentioned above, PJM has a very specifically defined role. Because the consequences of Reliability Violations can be severe, including equipment damage and involuntary load curtailments, PJM's mandate first is to maintain system reliability. That being said, however, PJM's planning process is expressly designed to be responsive to generation-based and DSM-based solutions developed through the marketplace, as well as merchant transmission solutions, and the resulting plan is reviewed each year to integrate the ongoing development of those alternative solution options.

Q. Does PJM conduct "integrated resource planning"?

A. Historically, the corporate entities that own transmission infrastructure also controlled a large portion of the existing generation resources. In years gone by, these entities could engage in integrated resource planning, which included both generation and transmission solutions for solving transmission reliability issues. However, FERC has mandated very specific prohibitions with respect to communications between the generation and transmission functions within these corporations, which include application to Dominion Virginia Power. FERC initiated these rules when electric deregulation began in 1992. The prohibition on communications is designed to encourage competition and the development of competitive markets in the energy industry. PJM's role is to facilitate the development of a wide variety of possible solutions and then determine if the aggregate of proposed market-based initiatives will be sufficient to ensure a reliable transmission infrastructure in the future. If not, then PJM is obligated to propose transmission solutions. PJM is not permitted to mandate generation or DSM solutions.

PJM's planning process is fully integrated in that it examines all needs with respect to transmission service and all solution options proposed through the marketplace. To the extent that transmission needs are not satisfied through market-driven solutions, the planning process will specify regulated transmission solutions to fill the gap. PJM's process does not represent "Integrated Resource Planning" in the historical context, in that there is no one decision-maker choosing between solution options, selecting one market-based solution over another, a market-based solution over a regulated solution, or vice versa. My understanding, however, is the Company is required under Virginia and North Carolina law to conduct Integrated Resource Planning in accordance with state and federal codes and standards of conduct.

Q. Please describe the PJM load forecasting model.

A. The model produces estimates of the monthly unrestricted peak loads of each of the 20 PJM zones, selected Locational Deliverability Areas ("LDAs") and the total RTO. Unrestricted load is the load prior to any downward adjustments for load management or voltage reduction. Forecasts are developed for each zone's non-coincident peak and the zone's share of the RTO peak. The econometric models are supplemented with a Monte Carlo estimation process to derive a distribution of forecasts over a wide range of possible weather conditions. PJM issues a load forecast annually and provides a mid-year update based on the most recently available econometric data.

Q. What are the primary drivers of the forecast?

A. The models are driven by calendar effects (day of week, month, minutes of daylight, etc.), anticipated economic conditions in the region and weather conditions.

Q. What does the PJM Load Forecast Report contain?

A. The load forecast report presents the results of PJM's forecasting model for the next 15 years; e.g., the 2012 PJM Load Forecast Report that formed the basis for analysis of the need for the Project presented results for the years 2012 through 2027 in Table B-1. For each PJM zone, region and the RTO, three years of monthly peaks and 15 years of forecasted seasonal peaks are presented. Table B-1 of the Load Forecast Report also presents the metered and unrestricted peak load from the most recent year for each transmission zone. The unrestricted peak load for a zone represents the load that would have been served at the time of peak had not some portion of the zonal load gone un-served, such as through the implementation of DSM programs. My Rebuttal Schedule 1, which is Table B-1 of the 2012 Load Forecast Report, shows for the entire Dominion Zone only 62 MW of DSM was provided during the 2011 system peak.

Q. How are considerations of DSM and energy efficiency handled in the PJM Load Forecast Report?

A. DSM is treated as an explicit adjustment to the unrestricted load forecast. As shown in Table B-8 of each Load Forecast Report, PJM includes load management that is committed through the RPM auctions to be delegated to PJM for dispatch at times of system emergency with mandatory compliance as a line item. Energy efficiency programs that are committed through the RPM auctions are also included as a line item in Table B-8 of the Load Forecast Report. Both DSM and energy efficiency programs are modeled in relevant planning studies as a load reducer. Both DSM and energy efficiency are identified for each of the coming three years based on the amounts that have been committed in RPM auctions for the particular delivery years. Beyond the third year of the load forecast, it is assumed that the amounts committed for the third year will remain constant into the future. Therefore, the Load Forecast Report will show the same amount of DSM and energy efficiency in years four through 15 as are shown in year three. My Rebuttal Schedule 2 is Table B-8 from the 2012 Load Forecast Report.

Q. Does PJM produce forecasts for areas within the zones?

A. No. The forecasts are only at the zone level. Distribution companies use the PJM zone forecasts to develop load studies down to the level of load buses.

Q. Please describe some of the uncertainties related to non-transmission solutions that you are concerned about.

A. PJM has had to deal with significant uncertainty in the RTEP process with respect to the placement of future generation resources. To date, approximately 85% of proposed generation capacity has dropped out of the interconnection queue. Many of these projects could have contributed to the resolution of future reliability problems on the PJM system and yet, despite the stated best intentions of developers, the uncertainty around these projects makes it inappropriate to consider them as solutions until they are well advanced in the process, i.e., until they have executed an Interconnection Service Agreement, the last step in the interconnection process following the performance of Feasibility, System Impact, and Facilities Studies. In the case of this Project, there has been virtually no generation development in the area of interest and none is currently in progress.

The uncertainties surrounding developing demand response and energy efficiency programs raise a number of concerns regarding their inclusion in the RTEP. As with proposed new generation, PJM must have a reasonable level of certainty as to the availability of these resources if the reliability of the grid is to depend upon them. Once generating resources are constructed, they can be expected to remain connected to the system for decades and their operational behavior is highly predictable. Demand response resources may or may not continue to be available to PJM from year to year. This suggests the need for a more conservative approach to the reliance on these resources over the 15-year planning horizon in the RTEP.

Q. Despite inclusion of demand response resources in the load forecast, are these resources generally well-suited to address unplanned transmission outages?

A. No. Demand response programs are not well-suited to address unplanned transmission system outages because they need to be called upon in advance of a grid emergency. As a result, they are normally used as a resource adequacy tool to reduce load on the highest peak load days when the availability of generation resources may be insufficient to serve customer load, not as a means of alleviating facility overloads following unpredictable transmission outages. Transmission outages, on the other hand, can occur at any time of year, not just during system peak. Also, participants in the demand response program generally are contractually obligated to interrupt only 10 times each summer during emergency conditions. New demand response products have been implemented that allow for unlimited interruptions, but the majority of customers still commit to only 10 interruptions. Using demand response to manage facility loadings related to possible line outages (for example, in anticipation of possible system problems from a forecasted weather event), is a non-typical use of such resources and will reduce the remaining availability of those demand response programs for peak load conditions for which they are intended.

Q. Is there recent data regarding the viability of demand response as a long-term solution in eastern PJM?

A. Yes. The amount of available demand response resources has decreased in mid-Atlantic PJM in the last reliability pricing model auction by over 9%. The amount of cleared demand response in the PSEG Zone in New Jersey has decreased by almost 20% and in the Baltimore Gas & Electric Zone by approximately 15%. The Potomac Electric Zone saw a decrease of 4.5%, while the Dominion Zone saw a very slight increase of 21 MW, which translates to a 1.6% increase.

In addition, PJM's Independent Market Monitor noted, in a recent study, levels of demand response resources "buying-out" of their BRA commitments in subsequent Incremental Auctions, i.e., entities who have DSM resources that have bid and cleared the BRA are buying out of their commitment in subsequent incremental auctions by bidding their load back in as demand. Such buy-outs can occur in any subsequent Incremental Auction following an initial commitment in a BRA, up to three months before the start of an operating period and the associated obligations are typically taken over by existing generation that had failed to clear in earlier auctions. The result has been that actual demand response commitments provided in the 2012/13 delivery year were only 74% of the commitments made in the BRA three years earlier.

Both issues suggest that demand response amounts that were included in earlier planning studies, due to their commitment through the RPM auction process, cannot be counted on in subsequent years and may have masked NERC Reliability Violations for which solutions may no longer be able to be implemented in a timely manner. Previously, when demand response amounts were increasing, concerns were raised that planning studies were too conservative, that demand response amounts would continue to increase making proposed transmission solutions unnecessary. Now we are seeing demand response committed in one year choosing not to commit in future years. Further, such decisions are made consistent with the timing of RPM auctions, i.e., three years before the relevant operating period, when there is little time to implement any other solution to problems that might arise from their decision. More problematic is the assumption in RTEP analyses that models both cleared DSM and uncleared generation in a given area, recognizing the potential for demand response customers to buy out of their commitments, as discussed above. If both sets of resources are modeled and crucial to resolving a Reliability Violation in an earlier planning study, the subsequent buy-out could well leave the system in an unreliable state with no time remaining in which to implement a more permanent solution.

Q. Do you believe that PJM has properly considered demand response in the RTEP as an alternative to building transmission lines in general and specifically for this Project?

A. PJM's market structures are designed to allow participants to offer alternative solutions which, when committed through the execution of an Interconnection Service Agreement or through clearing in an RPM auction, are included in the development of the RTEP. While demand response solutions have inherent uncertainties as compared to generation resources, we have included them in the development of the RTEP, in circumstances where they would be expected to be available for implementation, assuming that they will continue to be available in future years. In past years, when participation in demand response programs was growing, PJM's planning assumptions were somewhat conservative and reasonably balanced against the uncertainties that existed. Based on the practice of modeling both DSM commitments and uncleared generation and recent behaviors, with participation in critical areas dropping and DSM providers buying out of their commitments, it may be that we are over-relying on demand response as a long-term solution and that some degree of change is required with respect to the treatment of these resources in reliability studies. PJM's modeling practices related to these resources are currently under review in the PJM Planning Committee and can be expected to be changed in future RTEP analyses.

III. ALTERNATE TRANSMISSION PROPOSALS

Q. PJM also considers non-incumbent transmission proposals as alternatives to utility-built RTEP projects. What is PJM's process for considering such proposals along with utility proposals?

A. Over the last two years, PJM has received a number of transmission proposals from developers other than the incumbent transmission owner in a particular transmission zone. These proposals have been submitted for consideration as a means to resolve reliability and/or market efficiency needs on the PJM grid. In all cases, the parties submitting the proposals have indicated their expectation that, should their proposal be chosen as the most effective solution to a given need and included in the PJM RTEP, they would be entitled to build, own, and operate the facility and recover their investment through the PJM Tariff in the same manner as an incumbent transmission owner. To date, PJM has no FERC-approved procedures for considering such proposals, but has filed procedures with the FERC as part of the Order 1000 compliance filing made in October 2012.

In the absence of FERC-approved procedures, PJM has evaluated non-incumbent transmission proposals via the same procedures used to evaluate transmission proposals submitted by the incumbent transmission owners. It has been PJM's intent to perform these evaluations, ignoring the identity of the proposing entity, so as to select the most effective solution to the needs identified on the grid. If the most effective solution were one proposed by an entity other than the incumbent transmission owner, PJM would then evaluate the qualifications of the proposing entity to build, own, and operate a transmission facility in PJM and, if qualified, designate that entity as the party responsible for the construction of the facility. The party would ultimately be required to execute the PJM Transmission Owners Agreement and take on all of the responsibilities and obligations of a PJM transmission owner.

In the context of the Project, PJM evaluated a number of potential transmission solutions, including two 500 kV transmission line proposals and variations of two lower voltage transmission packages involving, primarily, 230 kV and 115 kV facilities. Some of these proposals were submitted to PJM for consideration by Dominion Virginia Power and some by LS Power.

Q. Turning to the specifics of this Project, JCC Witness Whittier questions PJM's analysis to the LS Power alternatives on pages 6-7 of his testimony. What LS Power alternatives were provided to PJM?

A. LS Power submitted several solution alternatives to PJM in response to the Chesapeake Energy Center ("CEC") and Yorktown Power Station ("Yorktown") generation deactivation notifications. On January 20, 2012, LS Power submitted a Great Bridge 500 kV proposal ("January 20 Great Bridge 500 kV proposal"), comprised of a number of different facility upgrades, intended to address the identified Reliability Violations that resulted from the CEC and Yorktown generation deactivation notifications.

On March 5, 2012, LS Power supplemented their original proposal with an additional recommendation to construct a new underground Surry-Skiffes Creek single circuit 230 kV cable and associated Phase Angle Regulator ("PAR") ("March 5 230 kV plus PAR proposal") in order to resolve those criteria violations. At that time, LS Power indicated that they were not ruling out the possibility that the line would ultimately be overhead, rather than underground. On April 19, 2012, LS Power again modified their proposal by withdrawing the January 20 Great Bridge 500 kV proposal to construct facilities not related to the James River crossing, focusing instead solely on the James River crossing from Surry-Skiffes Creek ("April 19 230 kV plus PAR underground proposal"). At that time, LS Power provided a cost estimate for a 230 kV under-river crossing and PAR. LS Power mentioned in the April 19 230 kV plus PAR underground proposal that they did not rule out an overhead crossing but were "initially skeptical of the technical feasibility" of an overhead crossing due to "sag issues" that could result in transmission towers "required to be over 1000 feet tall." On April 26, 2012, after PJM had posted their recommendation to submit the Project to the PJM Board for approval and the evening before PJM presented that recommendation to Stakeholders, LS Power proposed an overhead Surry-Skiffes Creek single circuit 230 kV facility plus PAR and provided a cost estimate for the circuit.

Q. How did the four different LS Power alternatives compare to the proposed Project to solve the Reliability Violations?

A. The proposed Project, in conjunction with several other proposed upgrades that are unrelated to the James River crossing all of which have since been classified as Pre-Projects by the Hearing Examiner's January 30, 2013 Ruling, solved all identified Reliability Violations resulting from the CEC and Yorktown deactivation notifications through the 15-year planning horizon. The long-term nature of the solution is particularly important in light of the lack of generation development in the area and the potential for further generation retirement.

The January 20 Great Bridge 500 kV proposal did not solve several criteria violations, including the overloads caused by the loss of the transmission facilities that cross the James River. Specifically, the loss of that tower line resulted in overloads of the Chickahominy-Waller 230 kV, Lanexa-Waller 230 kV and Yorktown-Whealton 230 kV lines. In addition, the January 20 Great Bridge 500 kV proposal did not resolve the NERC category C3 "N-1-1" criteria violation of the Huntsman-Thrasher 230 kV line. As a result, the January 20 Great Bridge 500 kV proposal was not considered to be a viable solution and, in any case, was withdrawn by LS Power on April 19, 2012 as discussed above.

PJM also evaluated the effectiveness of the 230 kV plus PAR underground proposal at the core of the March 5 and April 19 proposals. Operationally, the 230 kV Surry-Skiffes Creek line and PAR, whether underground or overhead, is a challenging solution. In order to make the 230 kV line effective, the PAR was added to the proposal to, essentially, force energy to flow across the line. However, the setting of the PAR, which determines the flow on the 230 kV line, impacts the energy flow on other transmission facilities on the Peninsula and south of the James River. There are a number of transmission line contingencies that would violate NERC Reliability Standards, absent the PAR. The PAR setting required to manage all of the contingency violations resulted in a very small operating margin between the operating limit of the PAR itself and Lanexa-Waller 230 kV line, which is conductor limited. Additional sensitivity analysis was performed to evaluate the retirement scenario of Yorktown Unit 2. For the Yorktown Unit 2 sensitivity, the 230 kV Surry-Skiffes Creek line and PAR is not a workable solution. There is no one setting that would allow the 230 kV line to operate without resulting in Reliability Violations on some other circuit. As a result, the 230 kV Surry-Skiffes Creek line and associated PAR was not considered to be a viable solution. By comparison, the proposed Project resolved all Reliability Violations, including those identified in the sensitivity analysis involving the retirement of Yorktown Unit 2.

Q. What actions did PJM and the PJM Board then take with respect to the Project?

A. Ultimately, PJM selected the 500 kV Surry-Skiffes Creek Project as the most effective solution and recommended it to the PJM Board for approval at their May 2012 meeting. The Board approved the Project based on operational considerations and its performance with respect to NERC Planning Standards, cost considerations, and the performance of the project in sensitivity analyses related to the possibility of further generation retirements at Yorktown. PJM then filed the cost allocation for the Project, along with others approved at that time by the PJM Board, with FERC in June 2012. FERC accepted the allocations in September 2012.

Q. What remedy did LS Power have to challenge PJM's selection of the Company's proposed Project over the LS Power proposals?

A. Their remedy would have been to invoke dispute resolution under the PJM Operating Agreement or, possibly, to file a timely protest of PJM's cost allocation filing at FERC.

Q. Did they take either action?

A. No.

Q. How were the Company's potential additional generation retirements factored into the RTEP analysis?

A. Based on public Dominion Virginia Power corporate documents, it was clear that additional generation at Yorktown was at risk of retirement. PJM performed sensitivity analyses to evaluate the performance of the various transmission projects should the Yorktown Unit 2 generation retire in addition to Yorktown Unit 1. Based on this analysis, the Company's proposed 500 kV Surry-Skiffes Creek line remained the most effective solution. The 230 kV Surry-Skiffes Creek line and associated PAR proved to be ineffective, with additional NERC Reliability Violations arising, including overloads to the PAR, itself. These violations would result in even greater costs associated with that project as additional infrastructure is required to ensure compliance with NERC Reliability Standards. As of this writing, PJM has received notice of the intended retirement of Yorktown Unit 2.

Q. Other Company witnesses have addressed the need for a robust 500 kV source to serve the North Hampton Roads Load Area. Does PJM believe there is a need for a new 500 kV source into this area?

A. Yes. The analyses performed by PJM, the Company, and the Commission Staff have all demonstrated the ineffectiveness of 230 kV transmission solutions. Based on the limited availability of DSM, the lack of new generation development, and the potential for further generation retirement in the area, it is critical that a strong new 500 kV source be introduced to support the long-term reliability of service to customers in the area.

IV. NEW AND REPOWERED OR RETROFIT GENERATION

Q. In what location would new generation potentially offset the need for the Project?

A. Additional generation in the North Hampton Roads Load Area could potentially offset the need for the Project.

Q. What generation is currently in the PJM generation interconnection queue in areas that would potentially offset the need for the Project?

A. The PJM interconnection queue does not, at this time, contain any generation interconnection requests that would potentially offset the need for the Project.

Q. The Staff recommended and the Company has agreed to provide further studies, at the Hearing Examiner's direction, to implement Staff Witness Chiles's six recommendations. Staff Witness Chiles's recommendation (6) is to assess whether preserving existing generation at the Company's Yorktown Power Station could eliminate the need for the Project in favor of a 230 kV transmission line solution. How does this additional study "fit in" to the PJM RTEP process?

A. There seem to be a number of unknowns associated with how the results of these additional studies will fit into the PJM RTEP process. First, while the retirement notifications for the Yorktown generating units could be withdrawn, it is unclear what the long-term viability of the units will be and what upgrades will be required to ensure that viability. Second, analysis of potential transmission solutions would have to be re-initiated to determine the onset of Reliability Violations and the most effective solution to resolve them. Depending on the likely lifespan of the un-retired Yorktown generation, any proposed transmission solutions would have to be viewed in the context of the need for future transmission reinforcements when the generation ultimately retires. While it is certainly possible that a viable short-term solution could be identified, it would require some amount of analysis followed by review with PJM's Transmission Expansion Advisory Committee ("TEAC") and consideration by the PJM Board. Whether such a course of action would be more effective and less costly, in the long-term, than the Company's proposed Project is difficult to say.

Q. If the Commission were not to approve the proposed 500 kV Surry-Skiffes Creek line, which was approved by the PJM Board, and authorize instead either a 230 kV line or the Chickahominy Alternative, would the revised Project be required to go back through the TEAC/PJM review process? If so, how would the Project schedule be affected?

A. Any alternative project would have to be reviewed by PJM for compliance with reliability criteria, presented to the TEAC, and reviewed with the PJM Board for approval. The Chickahominy Alternative was initially examined by PJM, so any further analysis should be limited, but there would be some period of delay before it could be presented to the PJM Board for consideration. Because 230 kV proposals have been shown not to resolve all NERC Reliability Violations, further analysis will be required and solutions to remaining violations developed before presentation to the TEAC and PJM Board. In either case, rejection by the Commission of the Company's Project as proposed may prevent completion of an alternative project or package of projects in time to meet the identified need date.

Q. Mr. Herling, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

Company Exhibit No. __
Witness: SRH
Rebuttal Schedule 1
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Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGIONS AND RTO
2012-2022

		METERED 2011	UNRESTRICTED 2011	NORMAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Annual Growth Rate (10 yr)
AEP		24,543	24,546	23,400	23,716	24,073	24,570	25,028	25,334	25,552	25,775	26,006	26,272	26,502	26,709	1.2%
	%				1.4%	1.5%	2.1%	1.9%	1.2%	0.9%	0.9%	0.9%	1.0%	0.9%	0.8%	
APS		8,975	8,975	8,550	8,625	8,762	8,951	9,126	9,248	9,345	9,440	9,539	9,659	9,758	9,850	1.3%
	%				0.9%	1.6%	2.2%	2.0%	1.3%	1.0%	1.0%	1.0%	1.3%	1.0%	0.9%	
ATSI		14,032	14,032	13,160	13,278	13,435	13,661	13,875	14,006	14,083	14,155	14,274	14,399	14,492	14,570	0.9%
	%				0.9%	1.2%	1.7%	1.6%	0.9%	0.5%	0.5%	0.8%	0.9%	0.6%	0.5%	
COMED		23,753	23,753	22,390	22,852	23,274	23,947	24,595	25,052	25,357	25,645	25,981	26,401	26,699	26,997	1.7%
	%				2.1%	1.8%	2.9%	2.7%	1.9%	1.2%	1.1%	1.3%	1.6%	1.1%	1.1%	
DAY		3,580	3,580	3,330	3,382	3,458	3,568	3,676	3,744	3,788	3,833	3,889	3,943	3,988	4,032	1.8%
	%				1.6%	2.2%	3.2%	3.0%	1.8%	1.2%	1.2%	1.5%	1.4%	1.1%	1.1%	
DEOK		5,642	5,642	5,520	5,592	5,685	5,819	5,945	6,011	6,068	6,123	6,199	6,281	6,330	6,385	1.3%
	%				1.3%	1.7%	2.4%	2.2%	1.1%	0.9%	0.9%	1.2%	1.3%	0.8%	0.9%	
DLCO		3,012	3,070	2,920	2,935	2,980	3,045	3,102	3,132	3,158	3,181	3,210	3,246	3,270	3,289	1.1%
	%				0.5%	1.5%	2.2%	1.9%	1.0%	0.8%	0.7%	0.9%	1.1%	0.7%	0.6%	
DIVERSITY - WESTERN (-)					1,689	1,737	1,769	1,901	1,828	1,822	1,869	1,914	2,081	2,019	2,016	
PJM WESTERN		83,310	83,318	77,650	78,691	79,930	81,792	83,446	84,699	85,529	86,283	87,184	88,120	89,020	89,816	1.3%
	%				1.3%	1.6%	2.3%	2.0%	1.5%	1.0%	0.9%	1.0%	1.1%	1.0%	0.9%	
DOM		20,085	20,147	19,250	19,550	19,980	20,598	21,164	21,544	21,871	22,193	22,562	22,937	23,239	23,537	1.9%
	%				1.6%	2.2%	3.1%	2.7%	1.8%	1.5%	1.5%	1.7%	1.7%	1.3%	1.3%	
DIVERSITY - INTERREGIONAL (-)					3,916	4,225	4,431	4,525	4,500	4,438	4,398	4,619	4,672	4,653	4,581	
PJM RTO		163,684	163,762	151,995	153,782	156,254	159,842	163,168	165,691	167,433	169,032	170,860	172,793	174,638	176,420	1.4%
	%				1.2%	1.6%	2.3%	2.1%	1.5%	1.1%	1.0%	1.1%	1.1%	1.1%	1.0%	

Note:
Normal 2011 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2011 and all forecast values represent unrestricted peaks, priorto reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Company Exhibit No. __
Witness: SRH
Rebuttal Schedule 2
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TABLE B-8

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AEP																
ENERGY EFFICIENCY	0	5	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LOAD MANAGEMENT	1,291	1,339	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048
TOTAL	1,291	1,344	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057
APS																
ENERGY EFFICIENCY	0	4	6	6	6	6	6	6	6	6	6	6	6	6	6	6
LOAD MANAGEMENT	329	536	858	858	858	858	858	858	858	858	858	858	858	858	858	858
TOTAL	329	540	864	864	864	864	864	864	864	864	864	864	864	864	864	864
ATSI																
ENERGY EFFICIENCY	12	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	562	397	925	925	925	925	925	925	925	925	925	925	925	925	925	925
TOTAL	574	401	928	928	928	928	928	928	928	928	928	928	928	928	928	928
COMED																
ENERGY EFFICIENCY	374	495	529	529	529	529	529	529	529	529	529	529	529	529	529	529
LOAD MANAGEMENT	752	938	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486
TOTAL	1,126	1,433	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015
DAY																
ENERGY EFFICIENCY	9	12	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LOAD MANAGEMENT	122	51	225	225	225	225	225	225	225	225	225	225	225	225	225	225
TOTAL	131	63	229	229	229	229	229	229	229	229	229	229	229	229	229	229
DEOK																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	51	47	88	88	88	88	88	88	88	88	88	88	88	88	88	88
TOTAL	51	47	88	88	88	88	88	88	88	88	88	88	88	88	88	88
DLCO																
ENERGY EFFICIENCY	0	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	94	172	215	215	215	215	215	215	215	215	215	215	215	215	215	215
TOTAL	94	173	218	218	218	218	218	218	218	218	218	218	218	218	218	218
PJM WESTERN																
ENERGY EFFICIENCY	395	521	554	554	554	554	554	554	554	554	554	554	554	554	554	554
LOAD MANAGEMENT	3,201	3,480	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845	5,845
TOTAL	3,596	4,001	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399	6,399
DOM																
ENERGY EFFICIENCY	2	6	50	50	50	50	50	50	50	50	50	50	50	50	50	50
LOAD MANAGEMENT	570	705	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
TOTAL	572	711	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366
PJM RTO																
ENERGY EFFICIENCY	581	728	804	804	804	804	804	804	804	804	804	804	804	804	804	804
LOAD MANAGEMENT	8,556	9,998	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165	14,165
TOTAL	9,137	10,726	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969

Notes: Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
Load Management detail appears in Table B-7.

Allen

REBUTTAL TESTIMONY
OF
MARK S. ALLEN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or "Company").

A. My name is Mark S. Allen and I am Manager, Electric Transmission Line Engineering for the Company. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering (*magna cum laude*) from West Virginia University of Technology in 1981. I am a Registered Professional Engineer in Connecticut, Kentucky, Michigan, Ohio, Pennsylvania, Virginia, Utah and West Virginia. I have 31 years of experience with the Company in both Transmission and Distribution. I started my career with the Company as a Project Engineer in Transmission Engineering in 1981. In 1985, I moved to Distribution Planning as a Planning Engineer in the Eastern Division and then returned to Transmission Engineering in 1989. I have experience in both overhead and underground transmission design.

Q. What are your responsibilities as Manager, Electric Transmission Line Engineering?

A. I am responsible for the coordination of all high voltage transmission designs (overhead and underground) on the Dominion Virginia Power system. This includes all new designs as well as upgrades and relocations. I manage the engineering activities for each project to ensure completion of construction specifications by the established target date. I am responsible for assuring that all such designs/specifications meet the established criteria for safety, reliability, and cost-effectiveness.

Q. Have you previously submitted testimony in support of the Company's Application in this proceeding?

A. I did not originally submit pre-filed direct testimony, but, as the Company advised the Virginia State Corporation Commission (the "Commission") and participants on February 4, 2013, I am adopting the pre-filed Direct Testimony of Company Witness James Cox, who has taken another position in the Company.

Q. What is the purpose of your rebuttal testimony?

A. The Company proposes to construct an overhead 500 kV transmission line from Surry Switching Station ("Surry Station") at the Company's Surry Power Station in Surry County across the James River to the proposed Skiffes Creek Switching Station ("Skiffes Station") in James City County (or "JCC"). For the reasons expressed in the Appendix filed in support of the Application and in the direct testimony that I am sponsoring, the Company did not propose, as an alternative to its 500 kV overhead line, that all or part of the 500 kV line be constructed underground, or by using a hybrid combination of underground and overhead construction. Certain of the Respondents, as well as public witnesses, have recommended in this proceeding, however, that the Commission require that any transmission line crossing the James River to Skiffes Station be constructed underground at 230 kV. My testimony will address these recommendations.

In addition, during the January 10, 2013 public hearing in this proceeding and in a subsequent pre-hearing conference on January 30, 2013, the Hearing Examiner directed the Company to present evidence regarding the feasibility, cost and advisability of constructing an underground 230 kV hybrid single circuit (1000 MVA) ("Alternative A") or an underground 230 kV hybrid double circuit (1000 MVA/circuit) ("Alternative B") both from Surry Station to Skiffes Station along the route of James River Crossing Variation 3, both of which I will call together the "Variation 3 Hybrid" conceptual route.[1] In responding to the Hearing Examiner's direction, I will describe the Company's approach to undergrounding of transmission lines, based on our use of and experience with underground construction and operation of such lines; compare the construction, reliability, and operation impacts of underground with overhead construction; address the questions raised by the Hearing Examiner regarding the 230 kV Alternatives A and B; and recommend that no part of the Surry-Skiffes Creek line be constructed underground. Rebuttal testimony regarding underground construction costs will be provided by Company Witness Walter R. "Trey" Thomasson, III. I also will provide the estimated construction costs for constructing the additional overhead transmission facilities necessary to resolve all of the violations of mandatory NERC Reliability Standards ("NERC Reliability Violations") not resolved by Alternatives A and B, as identified by Company Witness Peter Nedwick, as well as for JCC Witness Waine P. Whittier's suggested rebuild of the existing James River crossing of 230 kV Lines #214 and #263 between Isle of Wight County and the City of Newport News ("Alternative C"). Finally, I will comment on the pre-filed testimony of BASF Corporation ("BASF") Witness

[1] As directed by the Hearing Examiner, Alternatives A and B are to come ashore underground on the BASF property at the James River Crossing Variation 3 and then continue underground on that route to an underground-overhead transition station at BASF Drive and then continue overhead on that route along BASF Drive to Skiffes Station.

Vernon C. Burrows concerning certain aspects of the construction of the proposed overhead line.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, MSA, consisting of Rebuttal Schedules 1-5, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. In fulfilling its obligation to provide reliable electric service at reasonable rates, the Company utilizes overhead transmission facilities to meet customers' load demands in the most economical manner whenever possible. When determining whether to build overhead or underground transmission lines, the Company considers such factors as reliability, time to construct, operability and cost. Based on these considerations, currently only about 1.27% of the Company's total transmission system operating at 69 kV or above is underground, and of that percentage, none operates above 230 kV. As supported by the evidence presented by the Company in its direct, supplemental and rebuttal filings in this proceeding, the Company continues to recommend its proposed Project, including the 500 kV overhead Surry-Skiffes Creek line, as the most robust and cost-effective transmission planning solution to meet the identified need in the North Hampton Roads Load Area.

First, the overall reliability of an underground transmission line is not considered as good as an equivalent overhead line due to the time it takes to locate and repair an underground fault. Since customer reliability is a major concern in determining whether to build overhead or underground transmission lines, an overhead line should be constructed whenever a viable overhead route exists, as it does in this case.

Second, as stated in the Company's Appendix and explained later in my rebuttal testimony, the Company does not consider 500 kV to be a viable underground alternative. Further, as explained by Company Witness Nedwick in his rebuttal testimony, neither a single circuit nor a double circuit 230 kV line from Surry Station to Skiffes Station, whether underground or overhead, will resolve all of the NERC Reliability Violations identified by Mr. Nedwick for 2015 and would increase the load on the already stressed 230 kV transmission system in the South Hampton Roads Load Area.

Third, the Company has a responsibility to build a reliable system in as cost-effective a manner as possible. As further supported by Company Witness Thomasson in his rebuttal testimony, the cost for a 230 kV hybrid underground/overhead Surry-Skiffes Creek line, including Skiffes Station and work at Surry Station, would be significantly more than the cost of corresponding facilities for the Company's overhead 500 kV line.

Finally, unlike the Company's proposed Project, the length of time to construct either an underground line or the Alternative C proposed by JCC Witness Whittier far exceeds the required target date for this Project.

As Company Witness Nedwick in his rebuttal testimony and Staff Witness John W. Chiles have testified, it is not viable to construct the new 500 kV line underground, and a 230 kV line without additional transmission upgrades, whether constructed overhead or underground, does not meet the identified electrical need. Further, the much higher cost for an underground line, including the additional transmission facilities required to resolve the identified NERC Reliability Violations, would not meet the 2.5 times criterion for the Project to qualify for treatment as a pilot program under House Bill ("HB") 1319 and does not address the need in this case. For these reasons, and as supported by the Company's evidence presented in this case, the Company continues to recommend that no part of the Surry-Skiffes Creek line be constructed underground.

Finally, construction of the Surry-Skiffes Creek overhead line using the Updated Proposed Route will not compromise the current environmental remediation on the BASF property.

My rebuttal testimony is organized as follows:

I. Background on Company's Underground Transmission
II. Effects of Underground Transmission
III. HB 1319
IV. 230 kV Alternative Estimates
V. Issues Related to the BASF Property

I. BACKGROUND ON COMPANY'S UNDERGROUND TRANSMISSION

Q. What portion of the Company's transmission system is underground, and how does that compare to the portion that is overhead?

A. The Company's transmission system is comprised of approximately 6,406 miles of lines operating at voltages of 69 kV and above. Of this total, there are 23.5 miles of 69 kV underground lines, 0.075 mile of 115 kV underground lines and 57.8 miles of 230 kV underground lines, for a total of 81.4 miles. The underground facilities represent 1.27% percent of the total transmission system. Underground transmission facilities are rare on most utility systems with service areas comparable to the Company's area in Virginia and North Carolina.

Q. How has the Company approached the installation of underground transmission lines?

A. The Company is obligated to provide reliable electric service at reasonable rates to the public. We discharge this obligation by utilizing overhead transmission facilities to meet the load demands of customers in the most economical manner whenever possible. Underground installation has only been used in very limited circumstances. Examples include the Company's underground facilities in northern Virginia inside the "Beltway," where the congested urban nature of these areas prohibited an overhead corridor from being established. A more recent example is our Hayes-Yorktown project for which the portion of a new 230 kV line across the York River was installed underground, using an existing river bottom encroachment permit, to avoid conflicts with operations of U.S. military elements.

Q. Are there examples of lines in the Company's transmission system that were installed underground for specific reasons?

A. Yes. My Rebuttal Schedule 1, a spreadsheet entitled "Dominion Virginia Power 230 kV Underground Transmission Facilities," shows each 230 kV underground circuit in the system and lists the primary reasons each was installed underground. In summary, these underground circuits were required because (1) no feasible, cost-effective overhead alternative was available; (2) the line was built as a radial configuration for direct delivery to the customer, who requested underground service and paid for the construction; (3) underground construction was required by Virginia law; or

(4) underground construction was approved by the Commission as a pilot project.

Q. Has the issue of underground construction been raised in prior transmission line cases?

A. Yes, for many years. In most cases, putting transmission lines underground appears to be an easy or obvious answer to some, but that is simply not the case. It is no coincidence that utilities with service territories similar to that of Dominion Virginia Power have constructed most, if not all, of their transmission lines overhead. Undergrounding is also a frequent response from local governments when members of the public express concerns about a proposed overhead route. It should be noted, however, that in no case has the Commission required underground construction against the Company's best engineering judgment.

Between 2001 and 2008, underground construction was proposed by opponents of overhead construction, and rejected by the Commission in a series of four cases, three of which involved 230 kV projects in Loudoun County: Beaumeade-Beco and Beaumeade-Greenway, Case No. PUE-2001-00154; Brambleton-Greenway, Case No. PUE-2002-00702; and Pleasant View-Hamilton, Case No. PUE-2005-00018. The Commission's rejection of underground construction in the Brambleton-Greenway case was upheld by the Supreme Court of Virginia on appeal. The Pleasant View-Hamilton line ultimately fell under HB 1319, and a two-mile section of this line was installed underground. The fourth case, the Garrisonville project, Case No. PUE-2006-00091, involved a proposed five-mile double circuit overhead line in Stafford County. In that case, the Company proposed an overhead line but also had filed testimony stating it was not opposed to undergrounding the double circuit line as a pilot project for the purpose of gaining experience with a new underground technology, if the Commission found that to be in the public interest. The Commission approved underground construction of the line as a pilot project to permit the Company to gain that experience.

II. EFFECTS OF UNDERGROUND TRANSMISSION

Q. What are the Company's concerns about installing transmission lines underground?

A. As stated above, the Company has 6,406 miles of transmission lines, but only 81.4 miles are underground, or about 1.27% of the total system amount. When determining whether to build overhead or underground transmission power lines, the Company considers four main issues: reliability, time to construct, operability, and cost.

Reliability is a major concern in determining whether to build overhead or underground transmission lines. Overhead and underground lines each have reliability challenges, but it is obvious that a problem on an overhead line is easier to locate than on an underground line, and underground line outages are significantly longer than those on overhead lines. On average, most repairs on an overhead line can be completed within hours, but repairs to underground lines take days to weeks. The Company clearly understands the expectation that lengthy power outages are unacceptable. As a result, when we consider customer reliability, overhead lines are preferred.

The second issue, equally critical, is the time to construct. None of the transmission alternatives to the proposed Project can be completed by the June 2015 need date for the Project. Based on a previous 230 kV project of this nature, the minimum estimated construction time for 230 kV transmission Alternatives A or B to fully resolve 2015 NERC Reliability Violations is 60 months from issuance of a Commission order. This is based on the time required for the activities described in the Company's response to Question No. 22 of the Staff's Second Set of Interrogatories, a copy of which is provided as my Rebuttal Schedule 2. This 60-month construction timeframe is based on the availability of multiple contractors to attack this aggressive schedule. It is unlikely that this number of contractor crews can be obtained due to the limited resources that exist in the transmission underground construction industry. In addition, it would require the postponement of the retirement of Yorktown Units 1 and 2 during this construction period. Therefore, those undergrounding alternatives are not technically feasible from an electrical or need date standpoint. JCC Witness Whittier's proposed Alternative C rebuild of existing 230 kV Lines #214 and #263 requires rebuilding so much of the Company's 230 kV facilities in the area that it would take an estimated 10 years just to complete the facilities needed to address the 2015 NERC Reliability Violations. Since it takes 10 years to construct Alternative C and the additional compliance facilities to address the 2015 NERC Reliability Violations, the construction group did not address the additional time it would take to build the additional facilities needed to address the 2021 Reliability Violations caused by Alternative C.

By contrast, the length of time required to construct the overhead 500 kV line proposed in this Project is 15 months and is projected to be completed by December 31, 2014. With a timely order from this Commission, the entire Project, including the 230 kV Skiffes Creek-Whealton line, is projected to be completed by the May 31, 2015 need date.

Another issue is operability. Underground transmission lines add operating restrictions to the electric system. When power usage is low, normally in spring and fall, underground lines can raise the voltage on the grid to unacceptable levels. In order to avoid damaging equipment, both of the Company and its customers, these lines must be temporarily taken out of service, or sufficient reactive compensation facilities must be added to the system. So operability concerns also lead us to prefer overhead transmission lines. Underground lines present significant issues for "reclosing" after faults and also can present transmission operating issues from the effects of weather.

The fourth issue considered when determining whether to build overhead or underground is cost. Dominion Virginia Power has a responsibility to build a reliable system in as cost-effective a manner as possible. As explained in detail below, both of 230 kV underground Alternatives A and B not only cannot be constructed by the need date, but would cost $333.2 million more than the $155.4 million cost of the proposed Project.

Q. What factors would cause the underground installation of a transmission line to have a detrimental effect on the reliability of electric service?

A. Outages of transmission lines, both overhead and underground, are not common but when they occur it is very important to restore the line to service as quickly as possible because of the amount of power they carry within our system and the significant numbers of customers that can be impacted.

As stated above, an outage of an overhead transmission line can usually be repaired within a matter of hours. Location of the problem is easy to identify. Our system operator will know that the outage is on a certain line between two substations, and a visual inspection of the line via air or land will quickly disclose the location where repairs are needed. We can gain access to the site promptly by road and along the right-of-way itself. We maintain our own skilled personnel, equipment and materials to make such repairs promptly, and qualified contractors are readily available, if necessary. The line can usually be restored quickly. In most outage cases, such as those caused by a broken insulator or conductor, repairs take only a few hours. In very rare cases of a structure failure, restoration can be, on average, one to three days. Based on the Company's experience with repairs required for overhead lines over water, restoration may take slightly longer depending on the nature of the problem, but still much faster than an underground repair.

In contrast, location of a failure of an underground transmission line is more difficult and time-consuming. First, each cable must be tested to identify the failed cable. Complex fault location equipment is used to calculate a distance to the fault. When the damaged section of a land-based cable is identified, the site must be excavated sufficiently to provide access to the failed cable. Depending on the nature of the damage, the cables must either be repaired with a splice, or the entire section between existing splices must be removed from its protective pipe casing and replaced. Splicing a 230 kV transmission cable is highly specialized. We must rely on the very few contractors in the United States that can do this work. After such a contractor is on-site and the damaged area has been excavated, it may take several weeks to over a month to complete the entire repair operation. If the damaged cable must be removed and a new cable installed, the process takes even longer. In the case of the Northern Virginia failure in 2004, the fault was the result of steel h-pile being driven through the steel pipe and cable. Consequently, we knew exactly where the failure was so assessment and repairs began immediately. A temporary repair had to be installed around the failed/ruptured pipe to prevent additional leakage of the dielectric fluid. The fluid that did spill had to be cleaned up in accordance with environmental regulations. One of the specialized contractors referenced above was brought in to facilitate and complete the repair. An oil freeze had to be installed on each side of the failed section so the pipe could be reopened to make the splice. A temporary splice pit had to be installed at the splice location to maintain proper atmospheric conditions while making the repair. The end result was a five-week repair of this 230 kV cable and pipe.

However, if the damaged section is deep underneath the bed of the river, in a directionally drilled pipe-type cable system, as would be the case for either of 230 kV Alternatives A or B, the repair becomes much more difficult and time-consuming. This is due to the fact that the pipe can be as much as 60 feet below the bottom of the river bed. Specialized marine construction contractors, as well as cable installation contractors, would be required to locate and fully evaluate the damage, devise a repair plan, and execute the plan.

Q. Are there additional reliability differences between underground and overhead transmission facilities?

A. Yes, with respect to "reclosing" of circuit breakers after a fault occurs. When a fault occurs on an overhead transmission line, the line may not have been damaged and can be restored to service immediately. When our overhead transmission system experiences a fault, breakers open to protect the line but automatically and immediately "reclose" so that, if the line has not been damaged, the power flow in the line is interrupted only for a fraction of a second. This can be done safely because a fault event is usually a temporary condition for an overhead line. Arcing associated with a fault of an overhead line does not usually do significant damage to the equipment.

Automatic "reclosing" is not permitted on underground transmission lines because the fault will likely result in damage to the cable and its insulation and immediate reclosing would cause more extensive damage. The resulting damage would require the lengthy repair process that I described above. Therefore, when a fault occurs on an underground transmission line, we keep the line out of service until tests can be performed to determine the cause of the fault and ascertain the extent of damage to the cable. Typically such testing would take several days to mobilize personnel and complete.

Q. What are the voltage control problems associated with underground cables and how do they affect the operation of the Company's transmission system?

A. Due to the electrical characteristics of underground cables, namely the capacitance, voltages on such cables can rise to unacceptable levels during periods of light load. These excessive voltage levels can damage equipment and create situations where devices can no longer function as required under all operating conditions.

Q. Are underground lines immune from the adverse effects of weather?

A. No. In fact, one of the 230 kV lines under the Elizabeth River locked out in 2009 for a fault during Hurricane Ida. The storm sprayed salt water into the transition station and caused the cable terminations to flashover from the salt contamination. The circuit locked out as designed and was out of service until the termination could be repaired and cleaned. It is actually standard practice now to de-energize this line during a major storm preparation to prevent flashover damage.

Q. How do the construction impacts of underground transmission lines compare to those of overhead transmission lines?

A. On land, there are significantly more impacts with underground construction compared with overhead line construction. For overhead construction, pipe pile foundations will be vibrated into the ground approximately every 1,000 feet. This results in minimal land disturbance. In contrast, for the double circuit underground alternative, two trenches, each approximately six feet wide and five feet deep will need to be excavated for the entire length of the circuit. This will result in an estimated 11,733 cubic yards of soil excavation for every mile of underground construction.

For the river crossing, the overhead construction would be similar to the land construction, with pipe pile foundations installed approximately every 1,400 feet, resulting in minimal riverbed disturbance. For the underground construction, most of the river crossing would not be disturbed, as the cable pipes would be directionally drilled underneath the riverbed. However, at every splice point for the cable, a trench approximately 900 feet long, four feet wide, and 15 feet deep would be excavated in the riverbed in order to properly "overboard" and bury the cable splices. Due to the length of the river crossing, this would have to be done three times for each individual pipe. This results in a riverbed excavation of 36,000 cubic yards of sediment and riverbed for six pipes with three splices each.

Q. Should the Commission require any portion of a Surry-Skiffes Creek line to be constructed underground?

A. No. The proposed Surry-Skiffes Creek transmission line should not be constructed underground for the following reasons:

1. As stated in the discussion above, the overall reliability of an underground transmission line is less than an equivalent overhead line due to the time it takes to locate and repair an underground fault. The duration of an underground outage has been validated by the Company's own experience with underground transmission, as in the case of the Northern Virginia project discussed above. Since customer reliability is a major concern in determining whether to build overhead or underground transmission lines, an overhead line should be constructed whenever a viable overhead route exists.

2. The Company does not consider 500 kV to be a viable underground alternative. The only 500 kV underground cables in the United States are at the Grand Coulee Dam in the state of Washington, which are short generator connections from the dam to the adjacent switchyard, and these circuits are currently in the process of being replaced due to reliability concerns. As explained by Company Witness Nedwick, neither 230 kV Alternative A nor B can, without significant further additions to the transmission system, resolve all of the identified NERC Reliability Violations, and either of these alternatives would only increase the load on the already stressed 230 kV transmission system in South Hampton Roads.

3. The Company has a responsibility to build a reliable system in as cost-effective manner as possible. My Rebuttal Schedule 4 provides the estimated overhead transmission costs for Alternatives A, B and C. As shown there, the estimated

cost for the proposed 500 kV Surry-Skiffes Creek overhead line, including Skiffes Station and work at Surry Station, is $155.4 million, while the cost for a corresponding hybrid underground/overhead double circuit 230 kV line from Surry to Skiffes Station (Alternative B) is $440.4 million, representing a 2.83 times cost differential for comparison purposes. However, this does not account for the $48.2 million of additions to the transmission system that would be required to resolve the NERC Reliability Violations for 2015 not addressed by Alternative B. When those costs are considered, the cost of Alternative B for 2015 increases to 3.14 times that of the Company's proposed overhead Surry-Skiffes Creek line. And with the additional $26.7 million of additional compliance facilities required for 2021, the cost of Alternative B is 2.98 times that for the proposed Project. The cost to construct single circuit 230 kV Alternative A would be $273.8 million, but the additions to the transmission system that would be required for that alternative to resolve the identified NERC Reliability Violations for 2015 and 2021 would be those required to build Alternative B plus the same compliance facilities as for Alternative B to resolve NERC Reliability Violations in those years. Accordingly, the total cost is the same for both Alternatives A and B.

4. The length of time to construct either transmission Alternative A or B is a minimum of 60 months after issuance of the Commission's Final Order, which would mean completion in mid to late 2018, far exceeding the required summer 2015 need date for this Project. The overhead construction of the proposed 500 kV line is projected to be completed by December 31, 2014, while the total

Project, including the 230 kV line from Skiffes Creek-Whealton, will be completed by May 31, 2015.

III. HB 1319

Q. Has the General Assembly enacted legislation that affects the choice of undergrounding versus overhead construction?

A. In 2008, the General Assembly enacted HB 1319 establishing a limited pilot program requiring the Commission to approve undergrounding of a two-mile portion of the Pleasant View-Hamilton project (for which the Commission previously had rejected undergrounding), plus all or part of three more transmission lines of 230 kV or less by July 1, 2012. In 2011, the expiration date for this program was extended to July 1, 2014. The legislation establishes three criteria for a project to be eligible for approval as a qualifying pilot project: (1) undergrounding all or a part of a line must be technically feasible; (2) the estimated additional cost of undergrounding may not exceed 2.5 times the cost of placing the same line overhead (unless the public utility, affected localities and the Commission agree that a project not meeting this criterion may be accepted into the pilot program); and (3) the governing body of each locality in which a portion of the proposed line indicates, by general resolution, general community support for the line to be placed underground.

Q. What has been the Company's response to HB 1319?

A. The Garrisonville project was submitted prior to HB 1319 and was not eligible for inclusion in the HB 1319 program. The Commission approved undergrounding of the two-mile portion of the Pleasant View-Hamilton line, as required by HB 1319, in Case No. PUE-2008-00042. The Company filed applications, which were approved by the

Commission, to construct two additional underground transmission lines as pilot projects under HB 1319. The 0.71-mile Beaumeade-NIVO underground line was approved in Case No. PUE-2008-00063, and the 3.7-mile Ballston-Radnor Heights underground line was approved in Case No. PUE-2010-00004.

Q. Were these projects comparable to the proposed 500 kV Surry-Skiffes Creek line?

A. No. This case concerns the need to provide a new source of 500 kV bulk power to support reliable service within an extensive load area that includes the Peninsula, Middle Peninsula and Northern Neck. Each of these pilot projects addressed a much more localized need and affected a much smaller area. Moreover, the Company does not consider undergrounding to be a viable alternative for a 500 kV line. As stated in Appendix I.C.4 on page 58, the only 500 kV underground cables in the United States are short generator connections from the Grand Coulee Dam to the adjacent switchyard. These cables are actually in the process of being replaced with 500 kV overhead lines due to reliability concerns, as discussed in my Rebuttal Schedule 3.

Q. Would undergrounding the proposed 500 kV Surry-Skiffes Creek line qualify for treatment as a pilot program under HB 1319?

A. No. As Company Witness Nedwick in his rebuttal testimony and Staff Witness Chiles have testified, it is not viable to construct the new 500 kV line underground, and a 230 kV line without additional transmission upgrades, whether constructed overhead or underground, does not meet the identified electrical need. Further, as shown in my Rebuttal Schedule 4, the much higher estimated cost for either a single circuit or double circuit underground line, including the additional 230 kV facilities required to resolve the identified NERC Reliability Violations, would exceed the 2.5 times criterion for a project to qualify under HB 1319. As I have explained, the total Project cost of Alternative A for 2015 ($488.6 million) is the same as for Alternative B. Of this total cost, the cost attributable to a Surry-Skiffes Creek line is $439.8 million ($488.6 million total minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable costs for the proposed 500 kV line total $106.6 million ($155.4 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). Comparison of the costs for these comparable facilities shows that the cost of facilities associated with the underground/overhead alternative 230 kV line to Skiffes Station is 3.13 times for HB 1319 comparison purposes for the proposed 500 kV overhead line for 2015. Adding the $26.7 million of additional facilities required for either 230 kV alternative to achieve full compliance for 2021 produces a total of $515.3 million for the 230 kV alternative. Of this total, the cost attributable to a Surry – Skiffes Creek line is $466.5 million ($515.3 minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable cost for the proposed 500 kV line for 2021 compliance is $123.9 million ($172.7 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). This is 2.77 times the $ 123.9 million cost of the proposed 500 kV overhead line for HB 1319 purposes.

IV. 230 KV ALTERNATIVE ESTIMATES

Q. Please provide the Company's estimated cost of the additional transmission facilities that would be required for each of Alternatives A and B to resolve identified NERC Reliability Violations that are not resolved by those 230 kV alternatives.

A. These additional facilities are identified in Company Witness Nedwick's Rebuttal

Schedule 4, and the estimated costs of these facilities for Alternative A are shown on page 1 of my Rebuttal Schedule 4. The corresponding costs for Alternative B are shown on page 2 of that schedule.

Q. **Please provide the Company's estimated cost for 230 kV Alternative C.**

A. Currently, existing 230 kV Line #214 (Surry-Winchester) and Line #263 (Chuckatuck-Newport News), each with a transfer capability of approximately 500 MVA, cross the James River on common double circuit structures between Isle of Wight County and the City of Newport News. As described in the rebuttal testimony of Mr. Nedwick, Alternative C, suggested by JCC Witness Whittier, would tie the river crossing portions of these two circuits together to create one six-wire circuit between Chuckatuck and Newport News Stations, designated Line #263, with a combined transfer capability of approximately 1000 MVA. The river crossing portion of Surry-Winchester Line #214 would be replaced with a new single circuit river crossing with new 1000 MVA conductors.

Of course, the transfer capability of these rebuilt river crossings would be limited by the transfer capability of the onshore portions of these circuits unless they are rebuilt to provide approximately 1000 MVA. In the case of Line #214, this would mean rebuilding from the Isle of Wight side of the James River 30.29 miles back to Surry Power Station, and from the Newport News side 2.65 miles back to Winchester Station. In the case of Line #263, 6.25 miles would need to be rebuilt from the Isle of Wight side of the river back to Chuckatuck Station and 4.52 miles from the Newport News side back to Newport News Station. But this work only covers the facilities that are directly affected by this increase in transfer capability of these two circuits. Significant improvements also would be required to additional interconnecting facilities to prevent them from overloading due to the increased power flows on Line #214 and Line #263. As shown on page 3 of my Rebuttal Schedule 4, the total cost of improvements to rebuild Line #214 and Line #263 and address the resulting impacts on other facilities is $144.8 million.

Mr. Nedwick's rebuttal testimony also identifies a number of NERC Reliability Violations that are not resolved by Alternative C, lists the additional improvements to the transmission system that would be required to resolve those deficiencies and explains that the cost of these additional transmission system improvements must be included in the total cost of Alternative C. As shown on page 3 of my Rebuttal Schedule 4, we estimate the cost of these additional improvements to transmission facilities to be $82.1 for 2015 compliance and $181.9 million for 2021 compliance, bringing the total cost of Alternative C to $ 408.8 million. In addition, this work would require the postponement of the retirement of Yorktown Units 1 and 2 during the construction period of the 2015 compliance work, resulting in an additional $ 652 million for 2015 compliance. This would bring the total project costs to $1,060.8 million for 2015 compliance, which exceeds the $155.4 million of the Company's proposed Project by 6.83 times. Because the time to construct the transmission facilities for 2015 NERC Reliability Standards compliance (10 years) far exceeds the Project need date, no generation costs were prepared for 2021 compliance.

Q. Do you have any further comments regarding the constructability of Alternative C?

A. Yes. We have analyzed the feasibility of constructing Alternative C, which would require rebuilding most of the existing 230 kV system in the area. That analysis, which focused on the sequence for rebuilding the various components of the system and the feasibility of scheduling the outages of existing lines that would be required, shows that it would take a minimum of 10 years to complete just the construction required for 2015 NERC Reliability Standards compliance for Alternative C. Obviously, this is not a feasible solution to meet the identified electrical need date of June 1, 2015.

V. ISSUES RELATED TO THE BASF PROPERTY

Q. Do you agree with BASF Witness Vernon C. Burrows's comments on pages 9-12 of his testimony, regarding his assessment of the impact of the construction of the transmission line using the Updated Proposed Route?

A. No. Mr. Burrows has made several incorrect assumptions about our engineering and construction methods to support his position on page 2 of his testimony that the construction of the line using the "Variation 1 route would be a disaster." First, Dominion Virginia Power plans to use a pipe pile foundation design to support the transmission towers on BASF property, not Drilled Foundations as noted by Mr. Burrows on page 10 of his testimony. These pipe pile foundations will be approximately 42 inches in diameter and will be driven with a vibratory hammer to a depth of approximately 40-60 feet. This type of foundation design is minimally invasive and is generally considered to have little, if any, impact when used in sensitive areas such as wetlands as discussed by Company Witness Cathy Taylor. Additionally, Mr. Burrows's statement on page 10 of his testimony that it will be difficult to span the bluff at the river is not correct. The BASF Property already has a 115 kV line that transverses the property for over one mile to the Dow Substation located on the property, which supplies electricity to the property. The extension of this corridor to the River is another approximately 2,500 feet and in that expansion our preliminary design calls for four towers. As is also discussed by Company

Witness Taylor, Dominion Virginia Power will not locate any towers in the capped landfill in Area 4C of the BASF property as shown in BASF Witness Burrows's Exhibits VCB-2 and VCB-3, nor will any construction activities occur on this capped landfill. In fact our preliminary designs indicate we can easily span the majority of this area and will have only one tower in Area 4C. While the Company has not yet determined the precise location for this tower, and will not be able to determine this until the final engineering following approval of the route, preliminary plans indicate that the tower would be located in the southern portion of Area 4C, between the capped landfill and the unnamed tributary. In any case, the tower will not be located on the capped landfill. See Rebuttal Schedule 5 for a map showing Area 4C and preliminary tower location.

Q. What concerns does Dominion Virginia Power have regarding the Policies and Procedures that Mr. Burrows asks to be required for the construction of an overhead route on BASF Property?

A. Dominion Virginia Power complies with all Federal, State, and Local laws and established construction practices for the utility industry in the construction of transmission lines and associated facilities. Below I quote the relevant portion and respond individually to each of the requirements Mr. Burrows sets out on Pages 14 and 15 of his testimony.

1. "Clearing of roadways or access points for construction purposes should be avoided when possible . . . ." Dominion Virginia Power will use existing roadways for access to the construction locations, unless use of such roadways is not practical. Based on preliminary route review, all right-of-way and structure locations can be accessed from an existing roadway, driveway, or by using a short

ingress and egress route.

2. "Construction traffic and equipment should be minimized so that only the vehicles and machinery necessary are used." Dominion Virginia Power is in agreement with this statement.

3. "Construction activities should be coordinated with BASF . . . ." Dominion Virginia Power will work with BASF in developing construction practices within appropriate bounds provided that BASF's requirements do not impede Dominion Virginia Power's construction schedule, do not cause the Company to absorb excessive cost to the project, and do not conflict with the established safety and construction methods used by Dominion Virginia Power and its contractors.

4. "Construction practices that minimize disturbance of vegetation should be used to the extent possible." Dominion Virginia Power maintains and utilizes experienced and qualified construction firms in the construction of transmission lines. Additionally we assign to each project a Dominion Virginia Power representative experienced in transmission line construction to oversee all construction activities. Construction of the line will be done within the confines of the right-of-way except where we have to ingress and egress to the tower locations or for set up locations for the wire pulling activity.

5. "Construction activity in proximity to rivers and creeks should be avoided if possible, and otherwise undertaken with utmost care." Dominion Virginia Power is in agreement with this statement.

6. "Construction activity in proximity to remediation areas or areas identified as environmentally sensitive should be carefully coordinated with BASF, VDEQ, and USEPA." Dominion Virginia Power is in agreement with this statement.

7. "Tower locations should be determined with the objective of minimizing visibility and point of sight screening by retention of existing vegetation . . . ." Company Witness Mike Brucato discusses the Company's vegetation management practices in further detail; however, where possible, Dominion Virginia Power will make every effort to retain existing vegetation that will not interfere with the usage and reliable operation of the transmission line.

8. "Tower design and materials and conductor type should be selected to mitigate visibility." Dominion Virginia Power has filed with the Commission the structure type and route that will be used for this Project. These items will come under the provisions of the Certificate. The design, structure location, foundations, conductors, hardware, and so forth will be as the Company outlined in its Application.

Q. Mr. Allen, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

Company Exhibit No. __
Witness: MSA
Rebuttal Schedule 1

Dominion Virginia Power 230 kV Underground Transmission Facilities

Line No.	Installation Date	Substation (Transition)	Substation (Transition)	Area	Voltage	Mileage	Cable Type	Number of Circuits	Cables Per Phase	MVA Capacity	Network/ Radial	Local Factors Influencing Underground Installation Requiements
248	1997	Ox (Carlyle South)	Glebe (Potomac Yards North)	Potomac Yards	230 KV	3.10	HPFF	1	2	637	Network	Relocation Condition of Railroad R/W agreement-no OH route available
2023	1997	Jefferson St.(Carlyle South)	Glebe (Potomac Yards North)	Potomac Yards	230 KV	3.10	HPFF	1	2	637	Network	Relocation Condition of Railroad R/W agreement-no OH route available
257	1970	Churchland (Craney Island)	Sewells Pt. (Tanners Pt.)	Norfolk	230 KV	1.54	HPFF	1	2	531	Network	Underwater segment of OH Line-no viable OH route available
270	1986	Sideburn	Burke	Fairfax	230 KV	2.18	HPFF	1	1	336	Network	Dense suburban area-no viable OH route available
275	1970	Glebe	Crystal	Arlington	230 KV	1.23	HPFF	1	1	336/293	Radial	Urban area-no viable OH route available
276	1970	Glebe	Crystal	Arlington	230 KV	1.20	HPFF	1	1	336/293	Radial	Urban area-no viable OH route available
277	1983	Glen Carlyn	Clarendon	Arlington	230 KV	1.95	HPFF	1	1	336/293	Radial	Urban area-no viable OH route available
278	1983	Glen Carlyn	Clarendon	Arlington	230 KV	1.95	HPFF	1	1	336/293	Radial	Urban area-no viable OH route available
294	1985	Braddock	Annandale	Annandale	230 KV	3.58	HPFF	1	1	400/340	Radial	Urban area-no viable OH route available
297	1985	Braddock	Annandale	Annandale	230 KV	3.58	HPFF	1	1	400/340	Radial	Urban area-no viable OH route available
2036	1991/2012	Glebe	Radnor Heights	Arlington	230 KV	4.93	HPFF	1	1	336/293	Network	Urban area-no viable OH route available
2037	1991	Glebe	Davis	Arlington	230 KV	2.37	HPFF	1	1	336/293	Network	Urban area-no viable OH route available
2082	2003	Sewells Pt.	Navy South	Norfolk	230 KV	0.58	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2093	2003	Sewells Pt.	Navy South	Norfolk	230 KV	0.58	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2082	2005	Navy South	Navy North	Norfolk	230 KV	1.5	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2093	2005	Navy South	Navy North	Norfolk	230 KV	1.5	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2096	2008	Clarendon	Ballston	Arlington	230 KV	0.43	XLPE	1	1	240	Radial	Urban area-no viable OH route available
2098	2010	Pleasant View (Dry Mill South)	Hamilton (Breezy Knoll)	Loudon	230 KV	2.2	XLPE	1	2	1048	Radial	Suburban area-HB1319 Pilot Project & required by VA law
2099	2007	Churchland (Craney Island)	Sewells Pt. (Tanners Pt.)	Norfolk	230 KV	1.54	HPFF	1	2	600	Network	Underwater segment of OH Line-no viable OH route available
2116	2010	Beaumeade	Nivo	Ashburn	230 KV	0.71	XLPE	1	1	524	Radial	Suburban area-HB1319 Pilot Project
2119	2011	Garrisonville	Aquia	Stafford	230 KV	5.5	XLPE	1	2	1048	Network	Suburban area-UG construction as pilot project
2120	2010/2012	Garrisonville	Aquia	Stafford	230 KV	5.5	XLPE	1	2	1048	Network	Suburban area-UG construction as pilot project
2121	2012	Davis	Radnor Heights	Arlington	230 KV	2.56	HPFF	1	1	319	Network	Urban area-no viable OH route available
2122	2012	Hayes (Gaines Pt.)	Yorktown	Yorktown	230 KV	3.8	HPFF	1	2	600	Network	Underwater segment of OH Line-no viable OH route available
2130	2010	Beaumeade	Nivo	Ashburn	230 KV	0.71	XLPE	1	1	524	Radial	Suburban area-HB1319 Pilot Project
					Total Miles	57.8						

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following response to Question No. 22 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 22:

For each underground alternative to the Surry-Skiffes Creek line that was evaluated by the Company, describe in detail the identified potential impediments to timely construction of that alternative.

Response:

Two underground alternatives to the Surry-Skiffes Creek line were evaluated by the Company, both double circuit 230 kV high pressure fluid filled transmission lines. The first was a hybrid line underground from Surry Power Station to the shore of James City County, where the line would transition to overhead construction to the Skiffes Creek Switching Station. The second was for underground line the entire distance from Surry Power Station to Skiffes Creek Switching Station. Both alternatives involve similar impediments to timely construction.

Lead time for material to build underground transmission lines is much longer than traditional overhead construction. High pressure fluid filled cable has an approximate lead time of 18 months from order date. A cable order of this magnitude (92 miles or 133 miles of single-phase cable) may be even longer. Other items such as cable terminations and pressurization plants have approximate lead times of nine months or longer.

Detailed engineering surveys would need to be performed on the river crossing as well as any land portion of an underground transmission line. Items such as geology of the riverbed, dredging activities, utility crossings, and nearby military activities could have an impact on routing options for an underground alternative. The right-of-way for a six-pipe river crossing will be a minimum of 400 feet wide in order to properly overboard the cable splices. In addition, a complete thermal route survey would need to be performed in order to ensure the transfer capacity of the underground alternative could be met with the assumed circuit configuration of three (3) three-phase sets of cable for each 1000MVA 230 kV circuit.

There are three known buried pipelines that cross the James River from the Surry Power Station property to James City County. These pipelines limit the optimal routing options across the river. These pipelines may have to be crossed with the transmission lines in the river, depending on the route selected. There will also likely be interference from any parallel pipeline's cathodic protection systems which would need to be studied and remedied if necessary. Also, the intake canal for the Surry Power Station would possibly need to be crossed.

There are limited contractor resources for the installation of high pressure fluid filled cable systems. In the area of the proposed crossing, the James River is shallower than the Company's previous crossing of the York River. Specialized vessels may be required to safely and efficiently work in the river.

An underwater crossing of the James River would require development by a qualified engineering and construction firm to determine the scope of issues and obstacles involved, and to develop a project activity schedule. Routing, right-of-way acquisition, environmental considerations, marine construction, civil engineering, electrical engineering, horizontal directional drilling construction, material acquisition, permitting, time-of-year restrictions, and weather are among the disciplines that would need to be considered to develop a detailed scope of work, cost estimates and a schedule for this type of project.

Grand Coulee Dam: Third Powerplant Overhaul Project

back>>

Projects to be Completed Prior to the Overhauls

Replacing 500 kV Cables with Overhead Lines

Underground, oil-filled cables currently transmit all power from the six TPP generating units to the 500kV switchyard.

In 1981, a single phase of an oil filled cable faulted, destroying all circuits in the tunnel that house the transmission lines for generating units G-22, G-23 and G-24. This fire instantly removed 2,415MW of power from the grid. It took approximately two years to plan, design and construct temporary overhead lines and another three years to replace the oil-filled cables. Once the oil-filled cables were replaced, the temporary overhead lines were abandoned in place. It has recently become apparent that the condition of underground oil-filled high voltage cables is degrading.

Replacing these oil-filled cables with overhead transmission lines solves several problems: Overhead transmission lines can be inspected and maintained more safely than oil filled cables; the new lines can support an up-rating of the TPP generators; and the replacement using an overhead route does not require long periods without generation to safely remove old cables and install new cables. Switching from the oil filled cables to overhead lines only constitutes a two week outage per generating unit while replacing the oil filled cables would take at least one year and cost over $250M in lost generation revenue. In order to remove the risk of another tunnel fire, support an uprate of units G-19, G-20 and G-21 and reduce operation and maintenance costs, USBR made the decision to remove the oil-filled cables install and install overhead transmission lines (Photo shows a simulation of the new towers and overhead lines).

The USBR approached Bonneville Power Administration (BPA) to assist in planning, designing and constructing the new 500kV overhead lines. The $18.5M construction phased of the project was awarded to Wilson Construction (Canby, OR). The new overhead lines will be energized in December 2012 and the oil-filled cables will be removed by December 2013.

Modifying the Fixed-wheel Gate Repair Chamber for Blasting and Painting

Each unit in the TPP has a single Fixed Wheel Gate (FWG), aka head gate. These gates need to be routinely inspected and overhauled, but this takes substantial manpower and unit outages. The unit outages required for each TPP generating units' mechanical overhaul are

an ideal time to inspect and overhaul the gates.

However, the FWG chamber is no longer in compliance with current life safety and electrical codes. At present, the wiring is not explosion-proof, ventilation is inadequate, separation from dam galleries is insufficient, and lighting is poor. Compounded, each of these factors lead USBR to the decision to extensively modify the FWG Chamber to ensure it is fully compliant with all applicable codes and regulations.

The $4M project was designed by the USBR and is being constructed by Knight Construction (Spokane, WA). The project is scheduled to be complete by February 2013.

Rehabilitating TPP Cranes

There are six cranes in the TPP, which will all be usec heavily use during the TPP unit overhauls. The TPP has two 275 ton upper bridge cranes, one 50 ton uppeı bridge crane, one 2,000-ton lower bridge crane, one 70 ton draft tube gantry crane, and one 275 ton forebay gantry crane. It is imperative that they all be in excellent working order prior to the overhaul work in order to prevent unplanned crane outages that coulc result in costly delays in the schedule.

Repairs and upgrades of these cranes in preparation for mechanical overhaul was the subject of an A/E crane consultants' inspection and report that was completed in September 2008. The A/E's report stated that the cranes were all in good condition and recommended, in lieu of a complete overhaul of the cranes, to the limit the scope of the project to crane controls. The $17M crane controls project was designed by CH2MHill, Inc. and the construction work is being performed by Dix, Inc (Spokane, WA). The project is scheduled to be complete by December 2012.

New Material Storage Building

Overhaul of the TPP turbines and generators requires lay-down space for all turbine and generator parts as they are removed. These and other incidental parts will occupy nearly all of the TPP floor space. There are a variety of spare parts and pieces presently being stored in the TPP that need to be removed in order to provide the needed overhaul lay-down space. These valuable and easily damaged spare parts need to be kept in a secure, climate and temperature controlled storage space. The new storage building was built adjacent to the TPP, providing a convenient location for movement of materials to and from the TPP. The building includes a 100-foot by 200-foot floor area with 30-foot walls, 30-foot by 28-foot door (same opening as the north TPP door), insulated walls and ceiling, heating and cooling, forced ventilation, power, compressed air, and a life safety system with fire suppression. The building is also certified LEED Silver.

The GCPO facilities are considered part of a historically significant area. As such, this new storage building cannot detract from the overall appearance of the area. The storage building is significantly smaller than the TPP, but retains the historical perspective of the site.

A design/build contract was awarded to Graham Construction (Spokane, WA) for $5M. The project is scheduled to be substantially complete in October 2012. Once the building is commissioned, Grand Coulee forces will begin moving material from the TPP into the Material Storage Building, freeing up lay down space for the TPP mechanical overhaul project.

TPP 236 MVA Transformer Replacement

The generator step-up transformer banks for generators G-19 and G-20 have been in continuous use since 1975. Identical transformers for G-21 were replaced in 2002 because of deteriorating conditions, and it was recently noted that the transformers for G-19 and G-20 are also beginning to show signs of deterioration. When these types of transformers deteriorate they produce flammable gases within the cooling oil. Close monitoring is required to prevent gas build up and the potential for explosion. Due to potential for explosion, access to this transformer area has been restricted. An explosive failure could damage cable circuit terminations and adjacent transformers which would compound immediate power loss and lengthen recovery time.

Spares for these transformers are not available in the Northwest. An additional motive for replacing these transformers is the forthcoming uprate of generating units G -19 and G-20. In order to uprate G-19 and G-20 from 690 MW to 770 MW, the single phase step up transformers required an uprate from 236 MVA to 276 MVA. The $28M project was designed by the USBR and the construction phase was awarded to Gardner Zemke (Albuquerque, NM) for $26M. The project was substantially complete in December 2011.

Rehabilitation of Two TPP Elevators

There are two freight/personnel elevators which will be in continual use during the TPP mechanical overhauls. One elevator is in the Turbine Erection Bay at the southern end of the TPP and the other in the Generator Erection Bay at the northern end of the TPP. It is imperative that both are in excellent working order prior to the overhaul work in order to reduce potential for elevator outages and costly delays in the overhaul schedule. The $2.3M project was designed by CH2MHill, Inc. and the construction phase was awarded to

ThyssenKrupp, Inc (Spokane, WA). This project is scheduled to be complete by January 2013.

TPP Governor Replacement

The TPP generators have a major role in reacting to normal load swings but also in reacting to power system transient conditions such as loss of critical transmission paths or varying load. However, the units have been experiencing failures and erratic behavior, therefore not responding as quickly as possible. The electric-hydraulic governors are also showing problems with obsolete electronic components. The printed circuit cards used epoxy-based operational amplifiers which are no longer being manufactured.

The six TPP governor control systems are currently being replaced with new digital governor controls. The new, faster responding governors allow for a more stable response to load rejection. The TPP governor hydraulic systems are in good condition and have not experienced major problems, so the scope of the governor replacement project is limited to replacement of the electronic components and pilot valve. Four of the new governor systems are currently online, one is being installed and the final unit is scheduled to be installed in January 2013. The construction phase of the $3M project was awarded to American Governor, Inc. (Amherst, WI) and is scheduled to be complete in May 2013.

TPP Exciter Replacement

The TPP generators have a major role in reacting to both normal load swings and to power system transient conditions such as loss of critical transmission paths. Generation dropping opens generator breakers and is used to decrease supplied power to compensate for loss of a similar quantity of load. In addition, the new modern, faster responding exciters have contemporary power system stabilizers which will enhance the overall stability of the units and the power system. Between generation drop and the power system stabilizers, the stability of the northwest power grid will be enhanced.

The excitation systems and associated equipment for the six TPP generators are being replaced with more robust and modern equipment. The previous excitation systems were state-of-the-art when first supplied in the late 1970s but the components have become obsolete and are difficult to replace. In addition, failures associated with the older excitation systems have created frequent unscheduled, forced outages of the TPP generators. Recently, one of the 805MW generators was forced out of service for several days by the failure of a small choke coil in the exciter regulator circuitry. Lost revenue is dependent upon time of year and availability of other TPP generators. However, an average one week forced outage of one TPP generator costs about $250,000 in lost revenue and approximately $800,000 if an additional unit is also forced out of service.

Four TPP units are currently operating with the new excitation system, one is currently being installed and the last unit is scheduled to be installed in January 2013. The construction phase of the $22M project was awarded to ABB., Inc (Montreal, Quebec) and is scheduled to be complete in May 2013.

Asbestos and Lead Paint Abatement

The Contractors performing work on existing equipment need may encounter asbestos or lead paint on some of the existing components. This is typically not an issue for components manufactured after 1980, however, these units were completed prior to 1980. Tests have confirmed that lead and asbestos do exist. The units will be cleaned prior to the overhauls by USBR and contractors who specialize in this field. The overhaul Contractors must be prepared with appropriate safety equipment, procedures, and trained staff to test for, handle and dispose of hazardous materials should they be encountered.

Permitting and Coordinating Activities

National Environmental Protection Agency (NEPA) compliance must be considered for all activities associated with the TPP overalls. Impacts to the environment need to be defined and addressed appropriately. Additionally, the GCPO facilities are considered part of a historically significant area. As such, any activity that could impact the overall appearance of the area could have an adverse effect and should be avoided if possible, and mitigation for the action applied if the action is unavoidable. The NEPA process has been completed for all of the TPP associated projects.

New Draft Tube Platform

The TPP unit overhauls will provide an opportunity to inspect and, if necessary, to repair the draft tubes. A specialize work platform is needed to complete the repairs, and the contractor performing the overhaul work will be responsible for fabricating it. The platform will be suitable for use on all three units undergoing overhauls.

On-Going Maintenance Programs in TPP

Throughout the execution of the overhaul program there will be operation and maintenance (O&M) work being performed by Reclamation staff. Units will be taken out of service for routine maintenance needs. Some of this work requires the use of the cranes and requires room for parts and equipment. Cavitation repair of turbine runners will be performed as a part of the routine maintenance and electrical testing of various components and will also be performed with repair work done as needed. These O&M activities may conflict with overhaul work, but will scheduled such that there are no delays to either O&M or the contractor.

TPP Operational Constraints

There are operational constraints regarding outages for the six units in the TPP. Typically, five of the six units need to be operational during the spring months to pass inflows to prevent total dissolved gas in excess of allowable amounts from being generated by spills. There are additional outage limitations during times of high power demand in July and August and during the winter months between mid-November through mid-February.

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Company Exhibit No. _
Witness: MSA
Rebuttal Schedule 4
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230 kV Alternative A Costs for 2015 and 2021
(Millions in 2012 Dollars)

Single Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$187.5
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$23.5
Surry Switching Station	$14.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$273.8

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Waller - C&O)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Build 2nd 230kV Surry - Skiffes Creek Line	$166.6
Total	$214.8

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek – Yorktown)	$18.7
Total	$26.7

Total Cost	**$515.3**

230 kV Alternative B Costs for 2015 and 2021
(Millions in 2012 Dollars)

Double Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$343.8
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$24.8
Surry Switching Station	$23.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$440.4

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Waller - C&O)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Total	$48.2

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek - Yorktown)	$18.7
Total	$26.7

Total Cost	**$515.3**

230 kV Alternative C Costs for 2015 and 2021
(Millions in 2012 Dollars)

Line 214, 263, & 261 Rebuild

Wreck & Rebuild 263 Line (Chuckatuck – Newport News) (land)	$26.8
Wreck & Rebuild 214 Line (Surry – Winchester) (land)	$61.3
New Single Circuit River Crossing for 214 Line	$37.5
Wreck & Rebuild 261 Line	$11.2
Temporary Line (263 Wreck & Rebuild)	$6.4
Add Capacitor Bank at Peninsula Sub	$1.6
Total	$144.8

Full Compliance Cost for 2015

Wreck & Rebuild 2113 Line (Lanexa-Waller)	$36.3
Wreck & Rebuild 34 Line (Skiffes - Grafton)	$17.3
Wreck & Rebuild 234 Line (Winchester - Whealton)	$0.5
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
R/P Transformer at Lanexa	$8.0
Total	$82.1

Additional Full Compliance Cost for 2021

Wreck & Rebuild 209 Line (Waller - C&O)	$35.6
Wreck & Rebuild 209 & 285 (C&O - Yorktown)	$11.4
Wreck & Rebuild 2102 (Tower Section) - Chickahominy - Waller	$59.7
Reconductor 2102 (Steel Pole) - Chickahominy - Waller	$1.9
Wreck & Rebuild 99 Line (Peninsula - Whealton)	$17.3
Add Shellbank 230/115 Transformer	$8.0
Add Whealton 230/115 Transformer	$8.0
Add SVC at Skiffes Creek location	$40.0
Total	$181.9

Total Cost	**$408.8**

Company Exhibit No. __
Witness: MSA
Rebuttal Schedule 5
Page 1 of 1

$DGNSPEC$

Standard Transmission Construction	SURRY - SKIFFES CREEK AREA 4C APPROXIMATE TOWER LOCATION MAP				
Dominion 701 E. Cary Street Richmond, VA 23219		DRAWN	CHECKED	APPROVED	DATE	DRAWING NO.
	ORIGINAL	MWS	03/04/13		03/04/13	
	REVISION					CAD NO.

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surry-skiffes creek alt 1 skiffes creek layout kak.dxf 3/4/2013 12:28:58 PM

Thomasson

REBUTTAL TESTIMONY
OF
WALTER R. THOMASSON, III
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. My name is Walter R. "Trey" Thomasson, III, and I am an Engineer III, Electric Transmission Line Engineering for Dominion Technical Solutions, Inc. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Electrical Engineering from Virginia Tech in 2003. I received a Master of Engineering Management degree from Old Dominion University in 2007. I am a Registered Professional Engineer in the Commonwealth of Virginia. I started my career with the Company as an Engineer II in Electric Transmission Operations Engineering in 2008. In 2011, I moved to Electric Transmission Line Engineering and was promoted to Engineer III in 2012. From 2004 to 2008, I was employed by the U. S. Department of Defense.

Q. What are your responsibilities as Engineer III, Electric Transmission Line Engineering?

A. My responsibilities are to design, engineer, and provide operational and maintenance support for underground high voltage transmission lines.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to provide conceptual design and cost estimates for an underground 230 kV hybrid single circuit (1000 MVA) ("Alternative A") and an underground 230 kV hybrid double circuit (1000 MVA/circuit) ("Alternative B"), as directed by the Hearing Examiner in this proceeding. I also will address statements of James City County (or "JCC") Witness Waine P. Whittier, PE, comparing the Company's estimated cost to construct a 230 kV hybrid underground line from Surry Switching Station ("Surry Station") to Skiffes Creek Switching Station ("Skiffes Station") provided in Section I.C.4 of the Appendix ("Appendix Hybrid Estimate") with the estimates provided by LS Power to PJM Interconnection, LLC ("PJM") in support of LS Power's proposal to PJM for a hybrid single circuit line from Surry to Skiffes Creek.

Q. Are you sponsoring an exhibit in your rebuttal testimony?

A. Yes. Company Exhibit No. __, WRT, consisting of Rebuttal Schedules 1-10, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. My rebuttal testimony explains the routing, construction, equipment, and costs associated with the underground 230 kV hybrid single and double circuit lines (Alternatives A and B) investigated by the Company at the direction of the Hearing Examiner. I also provide a proper cost comparison between the Company's Appendix Hybrid Estimate and the LS Power estimate for its 230 kV hybrid line proposal.

My rebuttal testimony is organized as follows:

I. 230 kV ALTERNATIVES A AND B

Q. Please describe the 230 kV hybrid lines covered by the Hearing Examiner.

A. At the January 10, 2013 public hearing, the Hearing Examiner directed the Company to investigate whether a single circuit or double circuit 230 kV hybrid line could, or should, be constructed, and, if not, why not, to run overhead from Surry Station to an overhead-to-underground transition station at the shore of the James River in Surry County, then cross the James River underwater and, upon coming ashore on the BASF property along the Company's James River Crossing Variation 3 route, continue underground along that route until reaching the intersection of the James River Crossing Variation 3 route and BASF Drive, where an underground-overhead transition would be constructed. The line would then continue overhead from the transition station north with the Updated Proposed Route along BASF Drive and across U.S. Route 60 into Skiffes Station. The Hearing Examiner further directed that the overhead portions of the Variation 3 Hybrid would utilize galvanized steel monopoles. At the prehearing conference held on January 30, 2013, the Hearing Examiner directed the Company to conduct certain power flow studies of these single and double circuit hybrid lines, which he referred to as 230 kV Alternatives A and B. I will use his terminology.

Q. Please describe the conceptual design of 230 kV Alternatives A and B.

A. The Company does not propose, and in fact opposes, undergrounding for any portion of the Surry-Skiffes Creek line. However, in response to the Hearing Examiner's direction, the following is a conceptual description of Alternatives A and B. For both alternatives involved, the line would need to start the river crossing south of the existing pipelines in Surry County so that they would not need to be crossed in the river. Also, the river crossing would not follow the overhead James River Crossing Variation 3 route across the river, but instead be a straight line across. For both alternatives, the straight line river crossing portion is approximately 4.0 miles, and the land portion in James City County is approximately 0.78 mile. The land portion in Surry County is approximately 1.5 miles for both an overhead and an underground route. Both alternatives were evaluated using a high-pressure fluid-filled ("HPFF") cable system for the underground portion and single shaft monopoles for the overhead portions.

II. CONCEPTUAL DESIGNS

Q. Please describe the conceptual design of 230 kV Alternative A.

A. The route of Alternative A, the single circuit hybrid line, is shown in my Rebuttal Schedule 1. Alternative A would leave the north side of the 230 kV switchyard at the Surry Station and run overhead on double circuit 500 kV monopoles (to accommodate a future 500kV line) and cross the intake canal for Surry Power Station before turning east to run along the northern bank of the canal for approximately a mile before turning south, crossing the canal and the three pipelines (two natural gas transmission and one petroleum products) and then leaving the Surry Power Station site into adjoining property where an overhead-to-underground transition station would have to be built on the Surry

County shore of the James River because there is no room for the transition station on the Company's property north of the pipelines, and the adjoining Hog Island Wildlife Management Area to the north is not available. From this transition station, the route would continue, as stated above, underground across the James River, as shown in my Rebuttal Schedule 1, to the James City County side. For the river crossing, the single circuit HPFF cable system would consist of three horizontal directional drills for an equal number of pipes, with two sets of intermediate splicing platforms in three locations (six total platforms). The pipes would need to be separated by 20 feet, with 120 feet between the first two pipes and the third pipe, as shown in my Rebuttal Schedule 2. This extra distance, which is needed for when the cables are spliced together and the pipe is "overboarded" into the river on each side of the splicing platform, requires a minimum right-of-way width of 240 feet. Once on land at the James River Crossing Variation 3 landing point, Alternative A would consist of one trench with three steel pipes, each containing three cables (a total of nine cables), as shown in my Rebuttal Schedule 3. Once the underground line reaches the transition station at BASF Drive, the line would continue overhead to Skiffes Creek on double circuit steel monopoles to incorporate the existing 115 kV line in existing right-of-way.

Q. Please describe the conceptual design of 230 kV Alternative B.

A. The route of Alternative B, the double circuit hybrid line, is shown in my Rebuttal Schedule 4. As stated in Section I.C.1 on page 56 of the Company's Appendix, a double circuit 230 kV overhead line cannot be built out of the Surry 230 kV Switching Station because that would preclude the Company from building a 500 kV line out of that location in the future. Accordingly, Alternative B would leave the south side of the

230 kV switchyard at Surry Station as underground lines and would parallel the existing transmission corridor in a south-easterly direction and would cross the existing natural gas and petroleum products pipelines before leaving the Surry Power Station property and continuing to a temporary workspace site on the adjoining property where the drill rig would be located to commence directional drilling for the underground river crossing. Just before getting to the James River, the pipes would spread before crossing the river. In the portion of Alternative B from the 230 kV switching station and where it enters the water, the cable system would consist of two parallel trenches, each with three steel pipes containing three cables (a total of 18 cables), as shown in my Rebuttal Schedule 5. The two trenches would be separated by 20 feet to reduce mutual heating effects in order to maximize the ampacity of the circuit, requiring a minimum right-of-way width of 50 feet. For the river crossing, the HPFF cable system would consist of six horizontal directional drills for an equal number of pipes, with three sets of intermediate splicing platforms in three locations (nine total platforms), as shown in my Rebuttal Schedule 6. The pipes would need to be separated by 20 feet, with 120 feet between each pipe pair, requiring a minimum right-of-way width of 400 feet. This extra distance is needed for when the cables are spliced together and the pipe is overboarded into the river on each side of the splicing platform. Once ashore on the James City County side, the underground cable system from the shore to the transition station on BASF Drive would be the same as shown in my Rebuttal Schedule 5. After leaving the transition station, the two 230 kV circuits would continue overhead to Skiffes Creek on double circuit monopoles, which would parallel and adjoin the existing 115 kV line all the way to the Skiffes Station site and would require expansion of the existing right-of-way to 150 feet.

Q. Will the adjoining property south of Surry Power Station be available to serve as the site for the transition station on the Surry side and/or the temporary construction workspace for the drilling rig?

A. In addition to a site of approximately 1 acre for a transition station, we also would need approximately 2.2 acres (single circuit – a 240 feet by 400 feet area) or 3.7 acres (double circuit – a 400 feet by 400 feet area) of additional land for temporary work space for the drilling rig. We don't know the availability of that adjoining land for these purposes. We also would need a permanent right-of-way through that land for the line itself.

Q. Please describe the equipment that would be needed to transition from the overhead line construction to underground cables.

A. For a single circuit underground transition station with 3 pipes, there would be a graveled, fenced area approximately 150 feet by 100 feet that would contain the following pieces of equipment:

- One overhead line backbone structure (75-foot steel H-frame)
- Multiple pipe stands for underground cable terminations, current transformers and surge arresters
- Control house for protective relays, communications equipment, batteries and battery charger
- A prefabricated enclosure approximately 12 feet high by 12 feet wide by 45 feet long also would be required for pressurization equipment for the HPFF cable system (located at one of the transition stations, with a corresponding hydraulic crossover cabinet at the other transition station)

Each of the underground cables must be terminated in a large porcelain bushing-type insulator that is approximately two feet in diameter and 10 feet tall. These cable terminations are necessary to transition from the cable insulation to air insulation for the outdoor overhead components. To the average person, this facility would look like a conventional electric substation.

For a double circuit underground transition station with 3 pipes per circuit, there would be a graveled, fenced area approximately 200 feet by 200 feet that would contain the following pieces of equipment:

- Two overhead line backbone structures (75-foot steel H-frame)
- Multiple pipe stands for underground cable terminations, current transformers and surge arresters
- Control house for protective relays, communications equipment, batteries and battery charger
- A prefabricated enclosure approximately 12 feet high by 12 feet wide by 45 feet long also would be required for pressurization equipment for the HPFF cable systems (one at each transition station)

Each of the underground cables must be terminated in a large porcelain bushing-type insulator that is approximately two feet in diameter and ten feet tall. These cable terminations are necessary to transition from the cable insulation to air insulation for the outdoor overhead components. To the average person, this facility would look like a conventional electric substation.

Q. As mentioned by the Hearing Examiner during the public hearing and pre-hearing conference, please explain the Company's preference for a HPFF cable system.

A. The Company has experience and success with three river crossing installations using

HPFF cable technology at 230 kV. The first such installation was in 1970/1971 across the Elizabeth River between Portsmouth, Virginia and Norfolk, Virginia. This circuit has been in continuous operation for 40+ years with no major problems. Another parallel Elizabeth River crossing circuit was installed in 2007, and the third is the recently completed Hayes to Yorktown circuit.

HPFF and cross-linked polyethylene ("XLPE") cables age in different manners. HPFF cables are paper insulated, for which the primary aging mechanism is well known and is very temperature dependant (current flow dependant). This means that cables that are lower loaded will last longer than cables that are higher loaded. XLPE cables have polymeric insulation, and the aging mechanism is much more complex. Many aging factors influence the life of an XLPE cable system, including physical, chemical, physico-chemical, and electrical effects. Numerous specifications, qualification testing and strict quality control are required to obtain an industry expected design life of 40 years for XLPE cable.

While the industry standard for a cable system life expectancy is 40 years for XLPE, HPFF is expected to last much longer. This has been demonstrated for HPFF technology on the Dominion transmission system as noted above. In fact, many of the earliest HPFF installations that were installed in the 1930s in the United States are still in operation today (75+ years). XLPE cable at 230 kV has limited operating history in the United States, especially in submarine applications; therefore, its actual life expectancy is unclear. For a cable system of this magnitude and importance, such risk of uncertainty cannot be taken.

Riverbed disturbance would be much greater using an XLPE submarine cable system than a directionally drilled HPFF cable system. As discussed in the rebuttal testimony of Company Witness Mark S. Allen, the riverbed disturbance for the HPFF system would be at the drill entry/exit points and the area to be trenched after the splicing operations are completed. While this would be greater than required for the proposed 500 kV overhead line, it is much less than would be required for an equivalent capacity XLPE submarine installation. For the XLPE submarine cable system, a cable laying barge would tow a jetting sled that would be used to embed the cable upwards of 10-15 feet below the river bed. For a double circuit cable system with three cables per phase, this would result in 18 cable laying operations across the river.

If the need ever did arise to replace cable due to end of life concerns, it would be much easier and cheaper to replace the HPFF cable than the XLPE cable. HPFF cable could be installed in the same pipes as the existing circuits, which would only require excavation at the splicing locations in the river. New pipe would not need to be directionally drilled across the river. With the case of XLPE cable, since it would be directly buried across the river, the whole entire jetting operation from shore to shore would need to take place again. This operation would be much more expensive and disruptive to the riverbed.

It should also be noted that the Company hired independent consultants to help identify the best cable system for both the Elizabeth River and York River crossing projects. In both cases, HPFF technology was ultimately chosen based on its proven reliability and less environmental disturbance.

III. COST ESTIMATES

Q. Have you prepared cost estimates for 230 kV Alternatives A and B?

A. Yes, I have. For each of these alternatives, a single circuit was defined as having a capacity of 1000 MVA. These estimates were completed using the same basic parameters (e.g., material costs, labor costs, contingency factor), used to develop the Appendix Hybrid Estimate.

Q. Please provide the cost estimate for Alternative A.

A. The line portion of Alternative A is estimated to be $187.5 million, including $154.6 million for the underground portions, $30.3 million for the overhead portions, and $2.6 million for two transition stations. The estimated cost of Alternative A would also include $14.0 million for work at Surry Station (which includes $12.0 million for two reactor banks and $2.0 million for 230 kV breakers and equipment) and $23.5 million for the construction of Skiffes Station (which includes $6.0 million for one reactor bank), bringing the total estimated cost of Alternative A to $225.0 million.

Q. Please provide the cost estimate for Alternative B.

A. The line portion of Alternative B is estimated to be $343.8 million, including $323.9 million for the underground portions, $18.2 million for the overhead portions, and $1.7 million for the transition station. The estimated cost of Alternative B would also include $23.0 million for work at Surry Station (which includes $18.0 million for three reactor banks and $5.0 million for 230 kV breakers and equipment) and $24.8 million for the construction of Skiffes Station (which includes $6.0 million for one reactor bank), bringing the total estimated cost of Alternative B to $391.6 million.

Q. What would be the estimated total cost of the Project with Alternatives A and B, excluding the cost of any additional overhead transmission or generation facilities that may be required to resolve all reliability deficiencies identified by Company Witness Nedwick?

A. By adding the cost of the 230 kV Skiffes Creek-Whealton line ($46.4 million) and the costs for work at Whealton Substation ($2.0 million) and Lanexa and Yorktown Substations ($0.4 million), the cost of the total Project with Alternative A would be $273.8 million and the cost of the total Project with Alternative B would be $440.4 million, plus any such additional costs.

IV. APPENDIX HYBRID ESTIMATE

Q. How do Alternatives A and B compare to the Appendix Hybrid Estimate?

A. The Company's Appendix Hybrid Estimate reflects a conceptual route leaving underground from Surry Station to a location south of the existing gas pipelines at the shore of the James River in Surry County, then crosses the James River underwater to an underground-overhead transition station shortly after reaching shore on the BASF property along the James River Crossing Variation 1 route. From the transition station, this route continues overhead north along the James River Crossing Variation 1 route along BASF Drive and across U.S. Route 60 to Skiffes Station, as shown on my Rebuttal Schedule 7. Alternative B has a slightly longer (0.3 mile) crossing of the James River, as well as additional underground construction on the James City County side (0.78 mile), compared to the Appendix Hybrid Estimate, which results in a $33.8 million ($343.8 million vs. $310.0 million) higher line cost for Alternative B than the Appendix Hybrid Estimate.

As noted above, the total project cost for Alternative B (exclusive of full compliance costs) is $440.4 million. This includes $18.0 million (of the $23.0 million) at Surry Station for three reactor banks and $6.0 million (of the $24.8 million) at Skiffes Station for one reactor bank. These reactor banks are needed for voltage control during periods of light load due to the highly capacitive underground cable circuits. These reactor banks were identified during the recent planning studies and, therefore, were not included in the original Appendix Hybrid Estimate. By including the costs of these reactor banks, the total project cost for the Appendix Hybrid Estimate becomes $406.6 million. It should be noted that these additional reactor bank costs were not identified at the time the Company submitted its response to No. 21 of the Staff's Second Set of Interrogatories, as the additional planning studies had not been completed at that time. The Company's updated response to No. 21 of the Staff's Second Set of Interrogatories is provided as my Rebuttal Schedule 8.

V. RESPONSE TO WHITTIER COST COMPARISON

Q. On pages 9-10 of his direct testimony, JCC Witness Whittier claims that the Company's estimated costs for 230 kV underground construction of the Surry-Skiffes Creek line appear "extremely high" and that the LS Power estimate provided to PJM is "comparable to industry expectation." Is this an "apples to apples" comparison?

A. No. The LS Power estimate was for a single circuit 230 kV hybrid underground line at a capacity of 500 MVA. Dominion Virginia Power's estimate is for double circuit 230 kV underground lines at a capacity of 1000 MVA per circuit for a total of 2000 MVA. This is four times the capacity of the LS Power proposal. Each circuit of the Company's

Appendix Hybrid Estimate reflects three individual pipes with three cables each to achieve this capacity. For two circuits, this equates to six pipes or six different directional drills across the James River, each with three separate splice locations in the river. In addition to the James River crossing of 3.7 miles (landing at the James River Crossing Variation 1 location), Dominion Virginia Power's estimate includes 1.5 miles of underground construction on land from Surry Station to the river. This cost estimate was performed as a desktop study using actual material costs and estimates for labor and material based on Dominion Virginia Power's just-completed Hayes-Yorktown 230 kV single circuit crossing of the York River. Based on the Hayes-Yorktown project costs and the additional complexities at the James River, which are discussed in detail in the Company's responses to Nos. 22 and 45 of the Staff's Second and Fourth Sets of Interrogatories, the Company's cost estimates are justified as submitted. My Rebuttal Schedules 9 and 10, respectively, contain copies of these responses.

Furthermore, as explained in paragraph 3 on page 17 of Exhibit WDM-1, Appendix IX, to the testimony of Staff Witness Wayne D. McCoy, comparing underground transmission costs between projects on a cost-per-mile basis is very difficult:

> While it may be useful to sometimes compare the general cost differences between overhead and underground construction, the actual costs for underground may be quite different. Underground transmission construction can be very site-specific, especially for higher voltage lines. Components of underground transmission are often not interchangeable as they are for overhead. A complete in-depth study and characterization of the subsurface and electrical environment is necessary in order to get an accurate cost estimate for undergrounding a specific section of transmission. **This can make the cost of underground transmission extremely variable when calculated on a per-mile basis.**

(Emphasis added.)

To compare estimated project costs more accurately, the amount of transfer capability should be factored into the calculation. For the Company's estimate of $310 million for the double circuit 230 kV hybrid line, the cost per MVA of transfer capability is $155,000 ($310 million / 2000 MVA). For the LS Power estimate of $84 million for a single circuit 230kV hybrid line, the cost per MVA of transfer capability is $168,000 ($84 million / 500 MVA). Based on a comparison of transfer capability, the Company's estimate for the double circuit 230 kV hybrid line is actually lower than the LS Power proposal ($155,000 vs. $168,000). Also, for comparison sake, the Company's estimated $61.1 million for the proposed 500 kV overhead line using the Company's Updated Proposed Route, the cost per MVA of transfer capability is $14,127 ($61.1 million / 4325 MVA).

Q. Mr. Thomasson, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

Dominion

Surry-Skiffes Creek 500 kV Transmission Line

James River 230 kV Underground Crossing Alternatives

Alternative A

Single Circuit
Variation 3 Hybrid

Overhead Route
Underground Route
Drill Rig Temporary Workspace
Transition Station

N E S W
NATURAL RESOURCE GROUP

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Feet

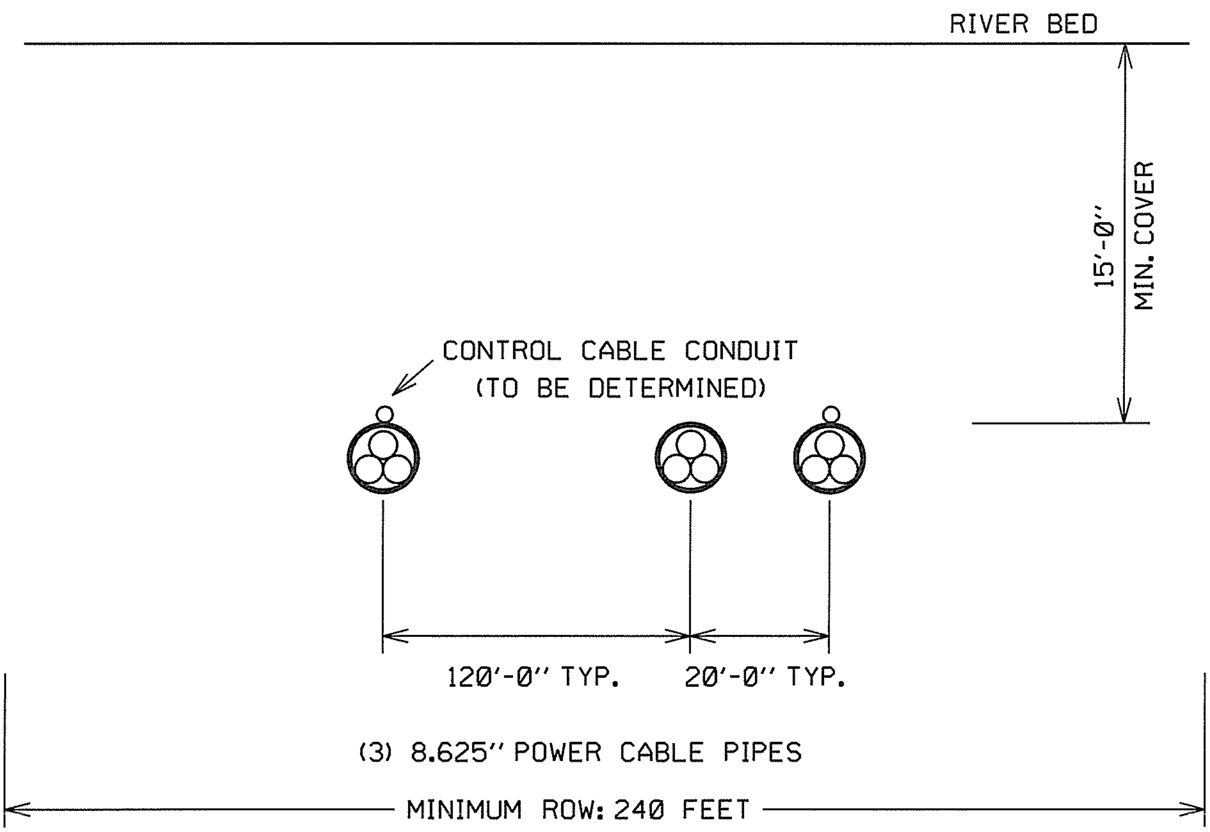
1:30,000

FILE: M:\Clients\D-F\DOM\Skiffes_ArcGIS\2013\02\Underground_Routes_SC_Var3_Hybrid_Route.mxd | REVISED: 02/19/2013

DRAWN BY: JPBOENTJE

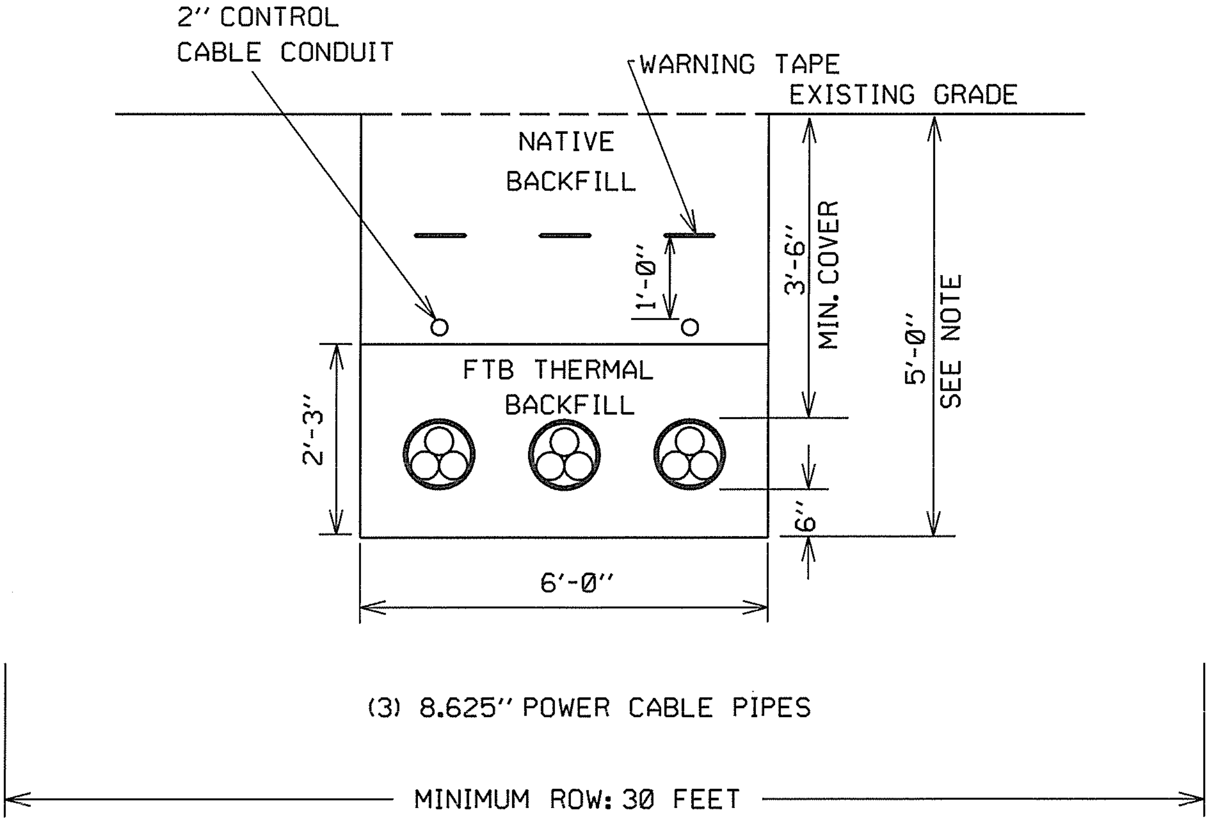
REBUTTAL SCHEDULE WRT-2

230 kV Alternative A
Surry - Skiffes Creek
Single Circuit HPFF Cable System (1000 MVA)
Underground River Crossing
Typical Horizontal Directional Drill Configuration



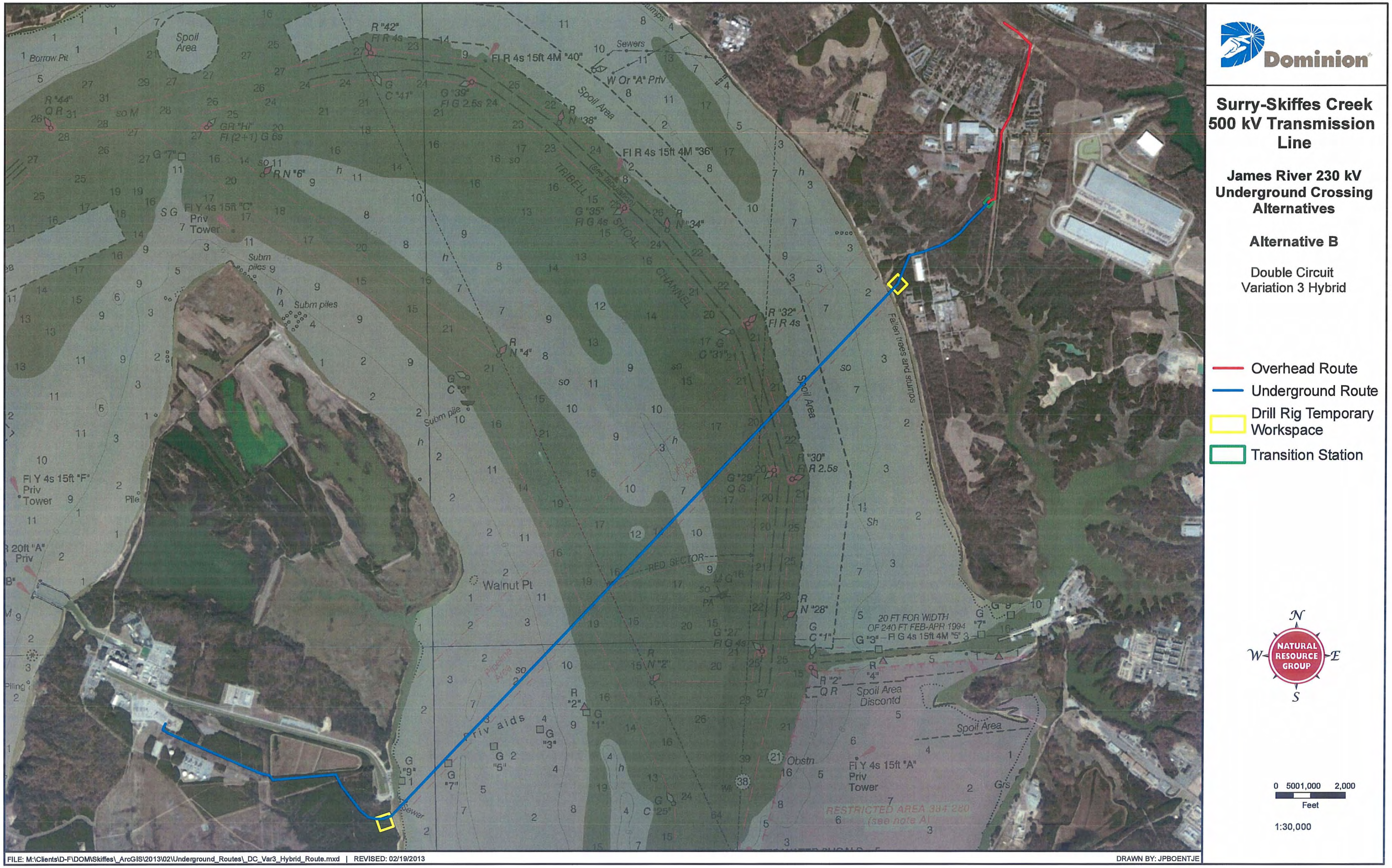
REBUTTAL SCHEDULE WRT-3

230 kV Alterative A
Surry - Skiffes Creek
Single Circuit HPFF Cable System (1000 MVA)
On-Shore
Typical Open Trench Configuration



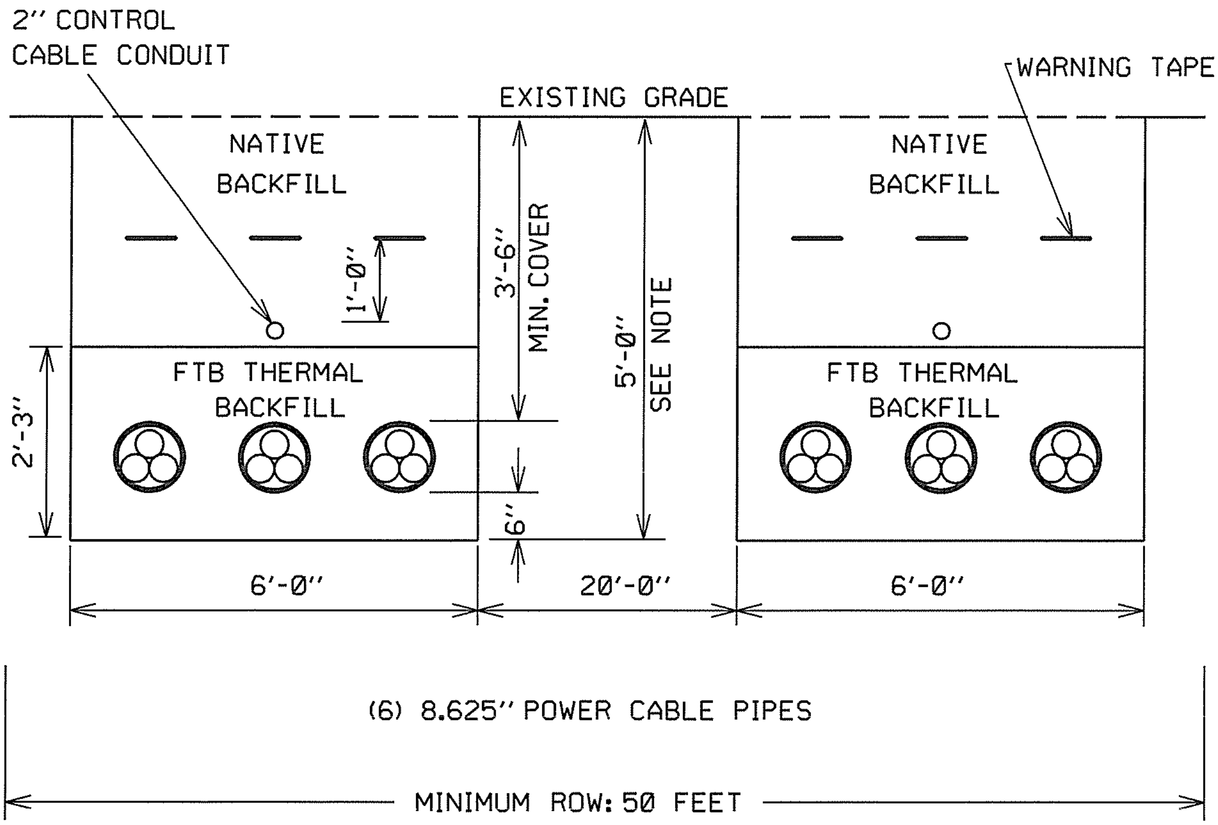
NOTE:
THIS DIMENSION WILL VARY DEPENDING ON CLEARANCES NEEDED WHEN CROSSING OTHER FACILITIES

Company Exhibit No. __
Witness: WRT
Rebuttal Schedule 4
Page 1 of 1



REBUTTAL SCHEDULE WRT-5

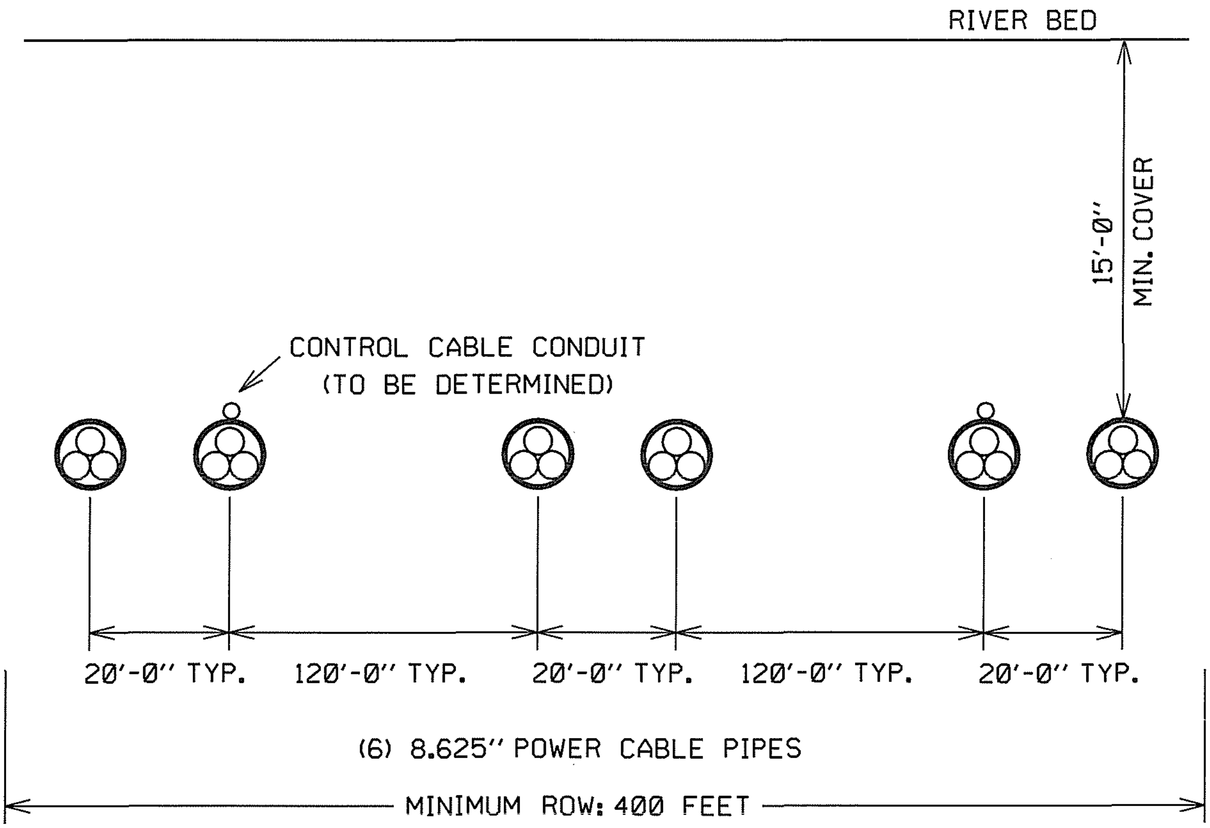
230 kV Alternative B
Surry - Skiffes Creek
Double Circuit HPFF Cable System (2 x 1000 MVA)
On-Shore
Typical Open Trench Configuration



NOTE:
THIS DIMENSION WILL VARY DEPENDING ON CLEARANCES
NEEDED WHEN CROSSING OTHER FACILITIES

REBUTTAL SCHEDULE WRT-6

230 kV Alternative B
Surry - Skiffes Creek
Double Circuit HPFF Cable System (2 x 1000 MVA)
Underground River Crossing
Typical Horizontal Directional Drill Configuration



Dominion

Surry-Skiffes Creek 500 kV Transmission Line

James River 230 kV Underground Crossing

Appendix Hybrid Estimate

- Overhead Route
- Underground Route
- Drill Rig Temporary Workspace
- Transition Station

N S W E
NATURAL RESOURCE GROUP

0 500 1,000 2,000
Feet

1:30,000

FILE: M:\Clients\D-F\DOM\Skiffes_ArcGIS\2013\02\Underground_Routes_Original_UG_Route.mxd | REVISED: 02/19/2013

DRAWN BY: JPBOENTJE

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following **REVISED** response to Question No. 21 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 21:
Reference page 20 of Company witness Nedwick's testimony, where it states that:

> Moreover, based on the Company's recent experience constructing 8-mile 230 kV Hayes-Yorktown Line #2122, including a 3.8-mile submarine crossing of the Rappahannock [sic] River, the estimated cost of the project, if this alternative were included, would be approximately $382.6 million for a hybrid line underground from Surry Power Station to the shore of James City County, where a transition, or terminal, station would be required to go from underground to overhead construction, and overhead from there to Skiffes Creek Switching Station. The estimated cost would be approximately $462.6 million for an underground line all the way to Skiffes Creek Switching Station.

Please elaborate on the "recent experience constructing ... Line #2122" and the estimates referenced by Mr. Nedwick. Include in this discussion the following:

(a) Provide the estimated cost of such construction at the time that the Company requested approval of Line #2122 from the Commission. Break down the total cost into the project's major components, including land and right-of-way acquisition, underground line, overhead line, transition station, and substation work.

(b) Provide the current estimated cost for construction of Line #2122. Break down the total cost into the project's major components, including land and right-of-way acquisition, underground line, overhead line, transition station, and substation work.

(c) To the extent the estimated cost provided by the Company in subsection (a) of this request differs from the cost in its response to subsection (b), provide an explanation of the reasons for the difference(s).

(d) Provide the current construction or operational status of Line #2122. Include the design capacity (MVA) of its underground portion, its overhead portion, and the total line.

(e) Describe in detail how the Company's recent experience constructing Line #2122 served as a basis for the $382.6 million and $462.6 million estimates included in this portion of Mr. Nedwick's testimony.

(f) Provide a detailed breakdown of the $382.6 million and $462.6 million estimates, including the project's major components, including land and right-of-way acquisition, underground line, overhead line, substation work, switching station, and transition station.

(g) Clarify whether the estimated costs included in the referenced portion of Mr. Nedwick's testimony are for a single-circuit or a double-circuit 230 kV alternative to the Company's proposed 500 kV Surry-Skiffes Creek line, including the number of three-phase cable sets and the capacity (MVA).

Revised Response:

(a) The original estimated cost for the Hayes-Yorktown project was $62.7M. All fee property was previously acquired, so no costs were allocated for land and right-of-way acquisition. The costs were broken down as follows:

- $47.5M for underground line work
- $8.4M for overhead line work
- $1.3M for transition station work
- $5.5M for substation work

(b) The current estimated cost for the Hayes-Yorktown project is $79.0M. All fee property was previously acquired, so no costs were allocated for land and right-of-way acquisition. The costs were broken down as follows:

- $62.2M for underground line work
- $8.7M for overhead line work
- $1.3M for transition station work
- $6.8M for substation work

(c) The major difference between the estimates provided in subsections (a) and (b) is the underground line work. The original estimate for the underground line was produced by an outside consultant. The cost of construction was considerably higher than originally anticipated. This became apparent during the construction bidding process. Also, there have been some unforeseen circumstances that have driven the construction costs higher. These circumstances include multiple construction delays involving cable installation, fiber optic installation, and splice over-boarding, as well as Hurricane Irene preparations and recovery and now Hurricane Sandy.

(d) As of this writing, Line #2122 is still under construction. Estimated energization date is December 2012. The underground portion of the line is designed for a 600MVA capacity at 0.95 load factor. The overhead portion of the line is designed for 604MVA. The total Line #2122 capacity will be set at 600MVA.

(e) Due to the Company's recent experience constructing Line #2122, material and construction costs from that project were utilized in the estimates provided by Mr. Nedwick's testimony. In addition as stated in subsection (c) of this response, there are multiple factors that can escalate construction costs. To accommodate for unknowns such as these that cannot be identified before hand a large underwater construction job, a contingency factor was included in the estimates.

(f) The estimated cost for a double circuit 230kV hybrid line underground from Surry Power Station to the shore of James City County and overhead from there to Skiffes Creek Switching Station is $406.6M. The costs were broken down as follows:

- $290.9M for underground line work and transition station
- $65.5M for overhead line work
  - $19.1M for UG Transition Station – Skiffes Creek
    - Including $0.8M for overhead line easements
  - $46.4M for Skiffes Creek – Whealton Line
    - Including $150k for overhead line easements
- $50.2M for substation work
  - $24.8M for Skiffes Creek Switching Station
  - $23.0M for Surry Switching Station
  - $2.0M for Whealton Substation
  - $0.4M for Lanexa and Yorktown Substations

The estimated cost for a double circuit completely underground from Surry Power Station to Skiffes Creek Switching Station is $486.6M. The costs were broken down as follows:

- $390.0M for underground line work
  - Including $0.8M for underground line easements
- $46.4M for overhead line work - Skiffes Creek-Whealton Line
  - Including $150k for overhead line easements
- $50.2M for substation work
  - $24.8M for Skiffes Creek Switching Station
  - $23.0M for Surry Switching Station
  - $2.0M for Whealton Substation
  - $0.4M for Lanexa and Yorktown Substations

(g) Both estimated costs ($406.6M & $486.6M) referenced were for double-circuit 230kV underground alternatives. Each circuit is estimated to have three (3) sets of three-phase cables for a 1000MVA transfer capacity. Combined, the double-circuit capacity would be 2000MVA utilizing six (6) sets of three-phase cables.

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following response to Question No. 22 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 22:

For each underground alternative to the Surry-Skiffes Creek line that was evaluated by the Company, describe in detail the identified potential impediments to timely construction of that alternative.

Response:

Two underground alternatives to the Surry-Skiffes Creek line were evaluated by the Company, both double circuit 230 kV high pressure fluid filled transmission lines. The first was a hybrid line underground from Surry Power Station to the shore of James City County, where the line would transition to overhead construction to the Skiffes Creek Switching Station. The second was for underground line the entire distance from Surry Power Station to Skiffes Creek Switching Station. Both alternatives involve similar impediments to timely construction.

Lead time for material to build underground transmission lines is much longer than traditional overhead construction. High pressure fluid filled cable has an approximate lead time of 18 months from order date. A cable order of this magnitude (92 miles or 133 miles of single-phase cable) may be even longer. Other items such as cable terminations and pressurization plants have approximate lead times of nine months or longer.

Detailed engineering surveys would need to be performed on the river crossing as well as any land portion of an underground transmission line. Items such as geology of the riverbed, dredging activities, utility crossings, and nearby military activities could have an impact on routing options for an underground alternative. The right-of-way for a six-pipe river crossing will be a minimum of 400 feet wide in order to properly overboard the cable splices. In addition, a complete thermal route survey would need to be performed in order to ensure the transfer capacity of the underground alternative could be met with the assumed circuit configuration of three (3) three-phase sets of cable for each 1000MVA 230 kV circuit.

There are three known buried pipelines that cross the James River from the Surry Power Station property to James City County. These pipelines limit the optimal routing options across the river. These pipelines may have to be crossed with the transmission lines in the river, depending on the route selected. There will also likely be interference from any parallel pipeline's cathodic protection systems which would need to be studied and remedied if necessary. Also, the intake canal for the Surry Power Station would possibly need to be crossed.

There are limited contractor resources for the installation of high pressure fluid filled cable systems. In the area of the proposed crossing, the James River is shallower than the Company's previous crossing of the York River. Specialized vessels may be required to safely and efficiently work in the river.

An underwater crossing of the James River would require development by a qualified engineering and construction firm to determine the scope of issues and obstacles involved, and to develop a project activity schedule. Routing, right-of-way acquisition, environmental considerations, marine construction, civil engineering, electrical engineering, horizontal directional drilling construction, material acquisition, permitting, time-of-year restrictions, and weather are among the disciplines that would need to be considered to develop a detailed scope of work, cost estimates and a schedule for this type of project.

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 45 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on December 7, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomassón, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 45:

Referencing the information below, please explain in detail the higher per-pipe-mile cost of underground construction in the Company's estimate for a hybrid 230 kV Surry-Skiffes Creek line versus the Hayes-Yorktown hybrid 230 kV line (Case No. PUE-2009-00049). Include an analysis of how the different fractions of directional-drilling (71% for Surry-Skiffes Creek and 79% for Hayes-Yorktown) affect the cost comparison.

Hayes-Yorktown

The following data is derived from the Company's response to Staff discovery request no. 2-21, and Case No. PUE-2009-00049:

- $62.2M for underground line work
- 2 pipes (1 circuit composed of 2 paralleled sets of 3-phase cables)
- 3.0 miles directionally-drilled (79% of the total 3.8-mile length)
- 0.8 mile trenched

(The drill pits are a short distance back on land from each shoreline. Thus, a small amount of the trenched distance may actually be directionally-drilled.)

The Staff calculates the per-pipe-mile cost for the underground portion of Hayes-Yorktown to be:

- $62.2M / 2 pipes / 3.8 miles = $8.2M per pipe-mile

Surry-Skiffes Creek

The following data is derived from the Company's responses to Staff discovery request nos. 2-21, 3-28, and 3-29:

- $290.9M for underground line work (includes the $1.7M transition station)
- 6 pipes (2 circuits, each composed of 3 paralleled sets of 3-phase cables)
- 3.7 miles directionally-drilled (71 % of the total 5.2-mile length)
- 1.5 miles trenched

The Staff calculates the per-pipe-mile cost for the underground portion of Surry-Skiffes Creek to be:

- $(290.9 - 1.7)M / 6 pipes / (3.7 + 1.5) miles = $289.2M /6 pipes / 5.2 miles = $9.3M per pipe-mile

Response:

The Company's estimate for a hybrid 230 kV Surry-Skiffes Creek line is higher on a per-pipe-mile basis than the Hayes-Yorktown hybrid 230 kV line for several reasons. First, the costs of project materials have increased over the last few years. For example, the price of cable – including raw materials such as copper – has increased over the last three years since the filing for Hayes-Yorktown.

Secondly, it is expected that three intermediate river platforms [per pipe pair] would be needed in the James River for the directional drilling instead of the two on the Hayes-Yorktown project. The additional platform would be needed for the following two reasons: (1) the James River has two distinct dredged shipping channels in the area of the Project route; and (2) the existing gas pipelines would need to be crossed with a directional drilling operation. An additional platform and the associated marine work significantly increase the cost on a per-pipe-mile basis.

Finally, as stated in the Company's response to Staff Set 2-21 (c) and (e), and Staff Set 2-22, the Surry-Skiffes Creek hybrid 230 kV line cost estimates include a contingency for unknowns and as a result of the issues associated with the Hayes-Yorktown project.

The cost estimates for the Surry-Skiffes Creek Project underground alternatives were not performed on a "fractional" basis of the Hayes-Yorktown project. The cost estimate for the hybrid Surry-Skiffes Creek line was performed as a desktop study using actual material costs and estimates for labor and directional drilling. For the reasons stated above, the per-pipe-mile costs are higher than the Hayes-Yorktown project.

Faggert

REBUTTAL TESTIMONY
OF
PAMELA FAGGERT
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. My name is Pamela Faggert and I am Vice President and Chief Environmental Officer of Dominion Resources Services, Inc., testifying on behalf of Dominion Virginia Power. My business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060-3308.

Q. What is your educational and professional background?

A. I have a Bachelor of Science degree in Chemical Engineering from the University of Virginia and a Master of Business Administration degree from Virginia Commonwealth University. I have over 18 years of experience in the electric power industry and 25 years in the environmental field.

Q. What are your responsibilities as Vice President and Chief Environmental Officer?

A. I manage a staff responsible for developing corporate environmental regulatory positions and providing environmental compliance support for Dominion Resources, Inc. This includes environmental permitting and biological and chemistry services. We represent the Company on environmental issues and support public policy staff on legislative issues. We also participate in the Company's strategic planning process for compliance with effective and anticipated environmental regulations.

Q. Have you previously submitted testimony in support of the Company's Application in this proceeding?

A. No, I have not.

Q. What is the purpose of your rebuttal testimony?

A. I wish first to address statements made in the Environmental Regulations Review Report by Mid Atlantic Environmental LLC ("MAE") dated January 11, 2013 to the Virginia State Corporation Commission ("Commission") in this proceeding and sponsored by Staff Witness Wayne D. McCoy of MAE as his Exhibit WDM-2 (the "MAE Environmental Regulations Report"). I also understand the Company has conducted additional studies in accordance with the Hearing Examiner's Ruling of January 30, 2013, which, in part, analyze potential alternatives, including generation at the Company's Yorktown Power Station ("Yorktown"). I will discuss the environmental restrictions on the operation of Yorktown Unit 3.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, PF, consisting of Rebuttal Schedule 1, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. As part of Dominion Virginia Power's strategic planning process to achieve cost-effective compliance with effective and anticipated environmental regulations, such as the Mercury and Air Toxics Standards ("MATS"), the Company identified multiple coal-fired generating units for retirement by 2015, including units at Yorktown. As explained by Company Witness Peter Nedwick in his rebuttal testimony, the planned unit retirements at Yorktown[1] had the effect of accelerating the need for a new 500 kV load source (the proposed Project) to be constructed in the generation-deficient North Hampton Roads Load Area from 2019 to 2015 in order to address violations of mandatory North American Electric Reliability Corporation ("NERC") Reliability Standards ("NERC Reliability Violations" or "Reliability Violations"). While Staff suggests that this strict timeline for construction of the Project could be shifted by requests for extensions of the 2015 MATS compliance date, the Company does not believe that the Yorktown units will qualify for such extensions under MATS. Further, there are no such extension provisions available to sources in the Clean Air Interstate Rule ("CAIR"), the ozone national ambient air quality standards ("NAAQS"), the sulfur dioxide ("SO_2") NAAQS or the proposed § 316(b) rule of the Clean Water Act ("CWA"), nor does the Company anticipate that such extensions will be available for anticipated regulations, such as the Coal Combustion Residuals ("CCR") Rule or the Effluent Guidelines Rule. Approval of the Company's proposed Project, including the construction schedule, will allow compliance with effective and anticipated environmental regulations on time.

[1] Although the Company's retirements analyses focus on "at risk" generating units, Company Witness Nedwick's rebuttal testimony explains that retirement of Yorktown Unit 1 accelerated the need for the proposed Project to 2015. Therefore, for the balance of my rebuttal testimony, I will focus on the units at Yorktown specifically.

My rebuttal testimony is organized as follows:

I. MATS Compliance
II. CAIR Compliance
III. Compliance with Anticipated Regulations
IV. Conclusion

I. MATS COMPLIANCE

Q. Do you have a response to the statements on page 3 of the MAE Environmental Regulations Report sponsored by Staff Witness McCoy that the MATS, "similar to other EPA regulations, does allow for evaluation of individual facilities, especially those currently in operation. Extensions can be granted, past the 2015 Compliance Date"?

A. It is true that the MATS provisions allow a source to apply for an initial one-year extension of the three-year compliance period. However, the statements in question oversimplify the matter, because certain reliability criteria must be met to qualify for an extension, as discussed in further detail below. If the Project is completed on time, the Yorktown units currently scheduled for retirement will not qualify for the one-year extension because they will not meet the reliability criteria.

Existing sources are required to comply with the MATS rule by April 16, 2015. Under the MATS rule, sources (individual electric generating units) are able to seek from the Title V permitting authority at the state level (in this case, the Virginia Department of Environmental Quality ("VDEQ")) an extension of the compliance deadline for up to one year as needed for the installation of controls. *See* Clean Air Act ("CAA") § 112(i)(3)(B); *see also* 77 FR 9304 at 9407 (Feb. 16, 2012). Extensions are made on a case-by-case basis. The U.S. Environmental Protection Agency ("EPA") provides guidance in the preamble to the MATS for the interpretation of the phrase "installation of controls" to include construction of compliant, on-site generation and unit retirement when:

> (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls;
>
> (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and
>
> (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

77 FR 9304 at 9410 (Feb. 16, 2012). Therefore, if the Project is completed as proposed, the units would not be needed for reliability as Mr. Nedwick explains, and so would not be able to meet the required reliability criteria argument (as outlined above) in order to request an additional year for compliance from the VDEQ.

Also in the preamble to the MATS rule, EPA addresses the situation where a company may seek an extension in order to replace retired generation with transmission upgrades, stating that: "While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that [this case] may provide reasonable justification for granting the 1-year extension…." *Id.* EPA believes that additional information would be necessary to seek an extension for this purpose, however, and that the Title V permitting authority should request "that the affected company…provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the

DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability." *Id.* EPA further explains that, in seeking the extension based on transmission upgrades, "it is the completion of the transmission upgrades…that would allow the retiring unit to come into compliance (by retiring) without threatening reliability." *Id.* at 9411. Thus, EPA believes that, if this situation arises and the reliability problem is "properly demonstrated, permitting authorities should consider whether an extension under CAA Section 112(i)(3)(B) may be provided." *Id.* Given the proposed schedule of the Project to be in service by June of 2015, combined with the fact that April through June are typically generation shoulder months for these units, the Company does not believe that the retirement of the Yorktown units would qualify as a "serious risk to electric reliability" because the Project addresses the NERC Reliability Violations and it can be built by June 2015, as explained by Company Witnesses Peter Nedwick and Mark Allen in their rebuttal testimonies. Specifically, Company Witness Nedwick supports the reliability need for the Project and Company Witness Allen provides testimony that the Project can be built by June 2015. I rely on their expertise and analysis of the reliability need for the Project and its ability to be constructed by June 2015 to conclude pursuant to the environmental regulations that the Company cannot claim that the retirements of the Yorktown units qualify as a "serious risk to electric reliability."

To request this one-year extension of the three-year compliance period (to a fourth year) from the VDEQ, the Company would need to apply in writing to VDEQ no later than 120 days prior to the April 16, 2015 compliance date (i.e., by December 17, 2014). EPA's regulations, specifically 40 CFR § 63.6(i)(6)(i), lay out the information a company must provide the permitting authority when it seeks an extension of the compliance deadline, specifically:

> (A) A description of the controls to be installed to comply with the standard;
>
> (B) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:
>
> > (1) The date by which on-site construction, installation of emission control equipment, or a process change is planned to be initiated; and
> >
> > (2) The date by which final compliance is to be achieved.
> >
> > (3) The date by which on-site construction, installation of emission control equipment, or a process change is to be completed; and
> >
> > (4) The date by which final compliance is to be achieved....

I have explained that in the MATS preamble, EPA interprets "installation of controls" to include retirement of a unit that meets certain electric reliability criteria. However, a company may submit a compliance extension request after the deadline date (in this case, by December 17, 2014, as noted above) provided that: (1) the need for the compliance extension arose after that date; (2) it is being requested before the otherwise applicable compliance date (in this case, by April 16, 2015); and (3) the need arose due to circumstances beyond reasonable control of the owner or operator. This request must include, in addition to the information required in 40 CFR § 63.6(i)(6)(i), a statement of the reasons additional time is needed and the date when the owner or operator first learned of the problems. In applying for the extension with the VDEQ, the Company would therefore need to include the information outlined in § 63.6(i)(6)(i), and the information that EPA discussed in the MATS preamble discussed above, notably that retirement within the three-year compliance period would result in a "serious risk to electric reliability" for each of the units contemplated to be retired at Yorktown.

The MATS rule also contains a provision allowing EPA's Office of Enforcement and Compliance Assurance ("OECA") to issue an additional one-year extension (to a fifth year) of the compliance deadline (i.e., until April 16, 2017), if necessary. OECA published a policy memo on December 16, 2011, outlining how the process works, including the use of an enforcement Administrative Order ("AO") for sources that must operate in noncompliance with the MATS rule for up to a year to address "a specific and documented reliability concern." Memo from Cynthia Giles, EPA to EPA Regional Administrators (Dec. 16, 2011). The policy is limited to sources that are critical for reliability purposes. Under § 113(a)(4) of the CAA, EPA may issue a nonrenewable AO requiring an entity to comply with an applicable requirement as expeditiously as practicable, but in no event longer than one year after the date the order was issued. Because a requirement must be applicable before an AO can be entered, EPA cannot issue an AO prior to the MATS compliance date of April 16, 2015. However, EPA intends to provide an owner or operator that has timely submitted a complete request for an AO as much advance written notice as practicable of the agency's plans with regard to the AO before the MATS compliance date. OECA's memo outlines the process for obtaining an AO for a unit that is required to operate for reliability purposes that would otherwise be deactivated. In summary, a source seeking an additional extension should:

- Provide early notice of its plan for complying with the MATS, including notice of the units it plans to deactivate and the units it plans to retrofit, to the appropriate transmission authority no later than April 16, 2013, which is one year after the MATS rule became effective on April 16, 2012.
- Submit to EPA and the FERC a written request for an enforceable

compliance schedule in an AO no later than 180 days prior to the MATS compliance date of April 16, 2015, which is October 18, 2014. A source must also submit a copy of this request to the appropriate transmission authority and the state environmental agency.

- The written request must contain the following information:
  - An analysis of the reliability risk if the unit were not in operation demonstrating that operation of the unit after the MATS compliance date is critical to maintaining electric reliability and that failure to operate the unit would (1) result in the violation of at least one of the reliability criteria required to be filed with FERC or (2) cause reserves to fall below the required system reserve margin.
  - A concurrence with the reliability analysis or a separate and equivalent analysis by the appropriate transmission authority. If such a concurrence cannot be provided, an explanation of why concurrence could not be provided must be submitted instead.
  - Comments from third parties in favor of, or opposed to, operation of the unit after the MATS compliance date.
  - A plan to achieve compliance with the MATS no later than one year after the compliance date or deactivate, and, where practicable, a plan to resolve the underlying reliability problem, which demonstrates that such resolution cannot be affected on or before the MATS compliance date.
  - An identification of the level of operation of the unit required to avoid the documented reliability risk and a proposal for operational limits or work practices to minimize or mitigate any HAP emissions.

See Id. at 6-7. If an applicant can make the reliability demonstration required in the OECA memo, EPA may issue an AO allowing operation of the unit for up to but no more than an additional one-year extension after the MATS compliance date (i.e., for a fifth-year extension until April 16, 2017), but it is not required to do so. Please note that there *are no provisions* in the MATS rule or mechanisms addressed in the preamble to the rule for compliance extensions beyond the fifth year, or in this case *beyond April 16, 2017*.

Under Clean Air Act § 113(b), EPA can bring civil judicial enforcement actions against sources that violate CAA requirements. This includes seeking injunctive relief and civil penalties (§ 113(b) authorizes the assessment of civil penalties of up to $37,500 per day for each violation). In addition, any person who knowingly violates a requirement of the Clean Air Act may be subject to criminal enforcement. My Rebuttal Schedule 1 provides a timeline illustrating the fourth- and fifth-year extension process under the MATS rule.

As explained by Company Witness Nedwick, the Company does not believe that the Yorktown units being retired will be needed for reliability after the Project is built. Therefore, because the Project can be built by the 2015 compliance date, as explained by Company Witness Allen, we do not believe a case could be made to VDEQ for a fourth-year extension of the MATS three-year compliance period or to EPA for an additional fifth-year extension under an AO.

II. CAIR COMPLIANCE

Q. Please discuss the statement made on page 5 of the MAE Environmental Regulations Report (Exhibit WDM-2) sponsored by Staff Witness McCoy that the CAIR "is currently being complied with and thus, would have no impact on the existing facilities."

A. CAIR does remain in effect today because the Cross State Air Pollution Rule ("CSAPR") was stayed and then vacated by the U.S. Court of Appeals for the DC Circuit. CAIR will not be replaced until (1) EPA promulgates a replacement for CSAPR, and (2) the states develop State Implementation Plans ("SIPs") and promulgate implementation rules. CAIR imposes emission reductions of nitrogen oxides (NO_x) and SO_2 on electric generating units through statewide emission caps in 28 states and the District of

Columbia to address the transport of these pollutants across state boundaries and assist these states in achieving and maintaining attainment of the ozone and fine particle ($PM_{2.5}$) national ambient air quality standards. NO_x is a precursor to ozone and fine particles, and SO_2 is a precursor to fine particles.

The Commonwealth of Virginia has chosen to achieve the required emission reductions under CAIR for both NO_x and SO_2 by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages. We are currently in the first stage of the NO_x and SO_2 emissions cap program under CAIR, known as "Phase I." In the second stage of the NO_x and SO_2 cap and trade programs, known as "Phase II," Virginia's statewide CAIR NO_x emissions cap will be reduced by approximately 17% starting in year 2015. This 17% reduction will be reflected in the amount of NO_x allowances the VDEQ allocates to CAIR budget units. To the extent that CAIR is not replaced by 2015 and remains in effect, the Virginia CAIR NO_x budget units will experience a reduced allocation in that year and going forward. In addition, under Phase II of CAIR, the current 2-to-1 Title IV SO_2 allowance surrender requirements of Phase I CAIR will be increased to a 2.86-to-1 ratio, which means affected generating units will need to surrender additional Title IV SO_2 allowances to comply with CAIR. Therefore, because CAIR becomes more stringent beginning in 2015 under Phase II, CAIR will have an impact on the Yorktown units compared to the current rules. However, the Yorktown units may utilize residual allowances from other facilities and/or banked allowances for compliance purposes.

III. COMPLIANCE WITH ANTICIPATED REGULATIONS

Q. Please discuss the statement made on page 5 of the MAE Environmental Regulations Report (Exhibit WDM-2) sponsored by Staff Witness McCoy that: "Under the National Pollution Discharge Elimination System ('NPDES') component of the Clean Water Act, cooling towers must have the best available technology to prevent or reduce their environmental impact."

A. We disagree with the statement as written. To clarify, § 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The CWA does not specify a particular best available technology, such as cooling towers. EPA is currently developing final regulations under § 316(b) which are expected by no later than June 27, 2013, unless extended by agreement.[2] Impingement controls are now expected to be required by 2021 and entrainment controls were originally expected to be required by approximately 2022 for minimizing adverse environmental impact. If the Yorktown units were to continue to operate, the Company has considered the technology options potentially necessary for capital upgrades that could be required to meet the § 316(b) rules, based on the current proposed rules. These options are found in Attachment V of the MAE Environmental Regulations Report (Exhibit WDM-2), DVP Environmental Regulation Discussion, pages 6 and 11, including Variable Speed Drive ("VSD") intake pumps, upgraded intake screens, new fish return systems and cooling towers.

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[2] *See* Settlement Agreement among the U. S. Environmental Protection Agency, Plaintiffs in *Cronin, et al. v. Reilly*, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in *Riverkeeper, et al. v. EPA*, 06 Civ. 12987 (PKC) (SDNY) (Nov. 22, 2010), available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316bsettlement.pdf.

Q. Please discuss the statement made on page 6 of the MAE Environmental Regulations Report (Exhibit WDM-2) sponsored by Staff Witness McCoy that: "This could require cooling towers and appurtenances by 2022, which may include water treatment for effluent discharges."

A. We disagree with the statement as written. To clarify, the effluent from cooling towers is commonly known as "blowdown." Blowdown may require water treatment prior to discharge, typically via a NPDES permitted outfall. Discharges from outfalls are known as effluent discharges. EPA is planning to propose another set of regulations to address effluent discharges from steam electric power plants. These regulations are the EPA's National Wastewater Treatment Standards for Steam Electric Industry, which are also known as the "Effluent Guidelines Rule." I will discuss the Effluent Guidelines Rule in further detail below.

Q. Are any applicable environmental regulations missing from Section II (pages 3-6) of the MAE Environmental Regulations Report (Exhibit WDM-2) sponsored by Staff Witness McCoy?

A. The Effluent Guidelines Rule is not discussed in Section II (Applicable Environmental Regulations) of the MAE Environmental Regulations Report. This proposed EPA rulemaking would establish national standards for wastewater at electric generating stations. Unless extended by agreement, EPA expects to release the proposed rule by April 19, 2013, and to take final action on the rule by May 22, 2014. The compliance dates for the final rule are expected to be between 2017 and 2019. The rule is expected to focus on Flue Gas Desulfurization ("FGD") wastewater, wet ash handling, landfill and surface impoundment leachate, metal cleaning wastes, and wastewater from flue gas mercury controls. The rule could also set standards for cooling tower blowdown, turbine wash, and boiler blowdown. These rules will likely require new or upgraded wastewater treatment facilities at the Yorktown Units 1 and 2. Given delays in its CCR rulemaking, EPA is expected to use the Effluent Guidelines Rule to drive changes in wet ash handling (e.g., establishing a no discharge standard that effectively prohibits wet ash handling). If these Yorktown units were to continue to operate, they may need to be converted to dry bottom ash handling (capital upgrades) to meet the Effluent Guidelines Rule. While not discussed in Section II of the MAE Environmental Regulations Report, a discussion of the Effluent Guidelines Rule can be found on page 6 of Attachment V of that report, entitled DVP Environmental Regulation Discussion.

Q. In their rebuttal testimonies, Company Witnesses Nedwick and Kelly refer specifically to environmental limitations on the operation of Yorktown Unit 3. Please describe those limitations.

A. The MATS rule contains a "limited use unit" provision that applies to a liquid oil-fired electric steam generating unit with an annual capacity factor of less than 8% of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015. 77 FR 9304 at 9400. A unit qualifying as a "limited use unit" will be subject to the periodic performance tune-up work practice requirements of the rule in lieu of the emission limits otherwise imposed. *Id.* at 9401. While the rule does not specify or define the contiguous 24-month blocks over which the annual capacity factor is averaged, it does not limit *when* or *at what capacity* a limited use unit can operate during any hour or day, except that its *annual* capacity factor (defined as the total annual heat input divided by the product of its maximum design heat input multiplied by 8,760 hours) averaged over a 24-month block cannot exceed 8%. This means that the unit can run at full load or partial load, during peak or non-peak loading times, as long as the annual capacity factor averaged over a two-year block does not exceed 8%. Also, please note that the "limited use unit" provisions do not include the ability or option to meet the qualifying criteria by averaging among multiple units.

IV. CONCLUSION

Q. Please respond to the following statements on page 7 of the MAE Environmental Regulations Report (Exhibit WDM-2) sponsored by Staff Witness McCoy:

> **In the regulations that do apply to existing facilities, EPA also makes it clear that it will review requests for extensions on a case by case basis. If, hypothetically, a project would require the continued use of an existing facility as a result of a construction constraint, MAE believes that EPA and the Virginia Department of Environmental Quality (DEQ) would be receptive to an extension. Whether it is transmission line construction or new generation construction, the regulations generally allow for extensions for cause. MAE, therefore believes that the strict timeline suggested by DVP could ultimately be shifted in order to provide the time necessary to implement a solution to electrical reliability in this region. While granting extensions for cause has been general practice in many environmental cases, until DVP and the appropriate agencies have specific discussions on timelines, there are no guarantees that this would be the case in this instance.**

A. The statements above are valid in limited circumstances for certain regulations and not valid regarding other regulations. For example, in the MATS regulations (discussed in more detail above), there are provisions for extensions of the compliance date of April 2015 provided certain reliability criteria are met <u>and</u> provided that:

- the state permitting authority exercises its discretion to grant the first year extension (fourth year extension until April 16, 2016); and

- EPA exercises its discretion to grant the second year extension (fifth year extension until April 16, 2017).

The Company has a plan to comply with the MATS regulations by the compliance date, which includes shutting down Yorktown Units 1-2 and building the Project on the proposed schedule. As stated previously, given its plan to construct the Project by June 1, 2015, the Company does not anticipate it could demonstrate that the Yorktown units contemplated to be retired pose a "serious risk to electric reliability" and have documented reliability concerns. Therefore, these units would not meet the fourth-year extension (from VDEQ) or fifth-year extension (from EPA through an AO) eligibility criteria. There are no extension provisions available to sources in the CAIR rule, the ozone NAAQS, the SO_2 NAAQS or the proposed § 316(b) rule. Furthermore, it is not expected that there will be extension provisions for the CCR Rule or the Effluent Guidelines Rule. While, on a case-by-case basis, there may be other ways to achieve compliance with certain effective and anticipated environmental regulations regardless of whether extensions are available (e.g., purchasing additional allowances), Company Witness Glenn A. Kelly explains the process used by the Company to determine that retiring the Yorktown units would be the most cost-effective solution for customers.

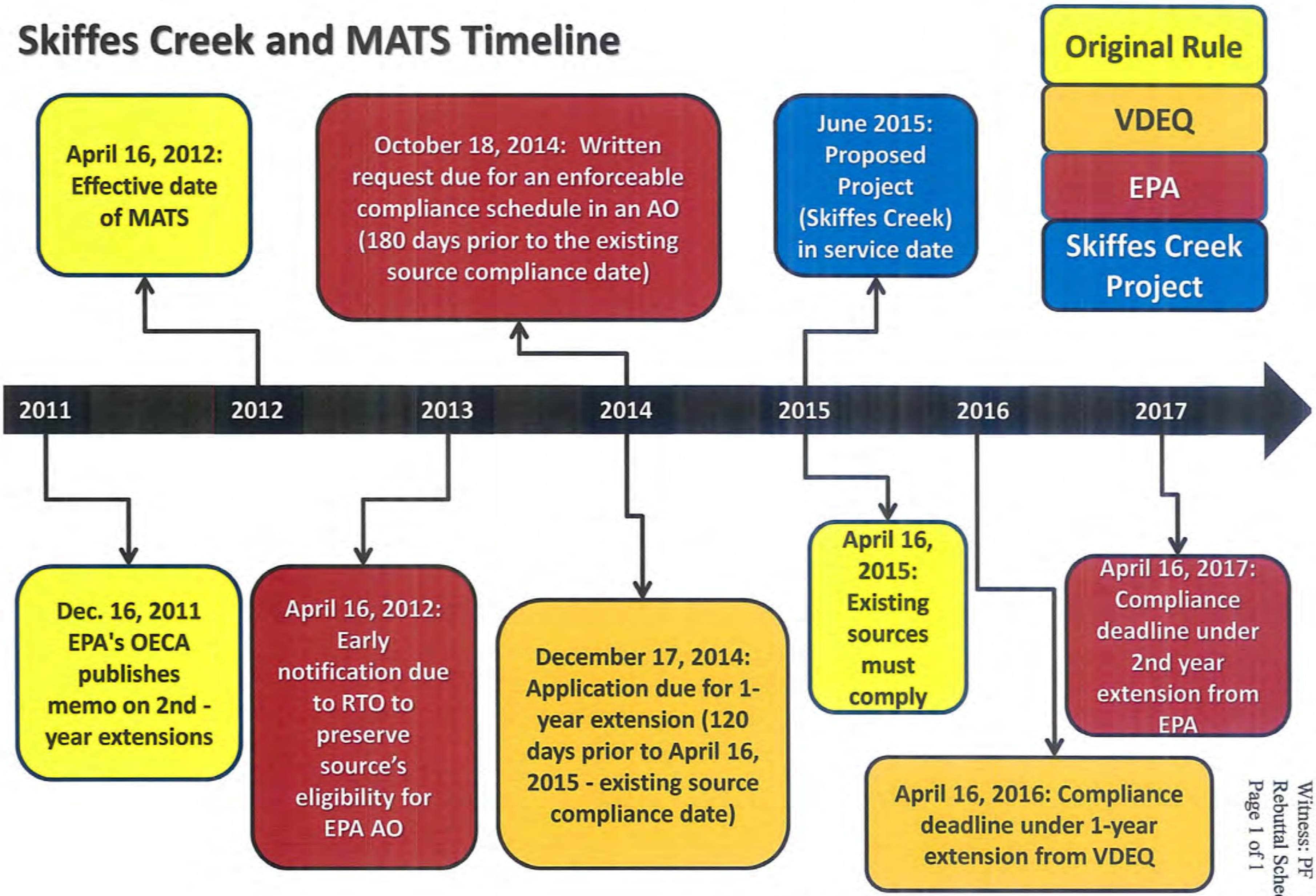
To the extent that the Project experiences unforeseen construction delays, coupled with meeting the reliability criteria as specified by the preamble of MATS as previously discussed in my testimony, VDEQ and EPA could each, under separate processes, exercise their discretion for a one-year extension of compliance with the MATS requirements. It is not at all clear that either environmental regulatory agency would be receptive to granting a delay where the Company could not demonstrate that it had attempted to meet the MATS compliance deadline on time. Approval of the Project by the Commission, including the schedule, would allow compliance on time.

Q. Ms. Faggert, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

Company Exhibit No. __
Witness: PF
Rebuttal Schedule 1
Page 1 of 1

Skiffes Creek and MATS Timeline



Note: Per the testimony of Pamela F. Faggert, at this time Dominion believes it does not meet the requirements for seeking these extensions.

Kelly

REBUTTAL TESTIMONY
OF
GLENN A. KELLY
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. My name is Glenn A. Kelly and I am Director of Generation System Planning for Virginia Electric and Power Company. My business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060.

Q. Have you previously provided testimony in this proceeding?

A. No, I have not.

Q. What is your educational and professional background?

A. I joined Dominion Virginia Power in 1986 as an engineer after graduating from Virginia Tech with a Bachelor of Science degree in Mechanical Engineering. I earned a Master of Business Administration degree from Averett University in 1998.

After working 11 years as a performance and project engineer at Chesapeake Energy Center and Yorktown Power Station, I transferred to the Company's Fossil and Hydro Technical Services Department in Richmond as a Generation Performance Specialist. In this capacity, I worked on various projects to improve and track unit efficiency within the generation fleet. Shortly after earning my MBA, I joined the Fossil and Hydro Financial Department, where I performed financial analysis using Strategist. Following a series of positions supporting Fossil and Hydro operations, I earned my Six Sigma Master Black Belt and became Manager of Planning and Analysis in April of 2004. My responsibilities included Energy Supply PJM support, fuel expense and variance reporting, generation forecasting, and project financial analysis.

In September 2007, I was promoted to Director Generation System Planning for Dominion Virginia Power. I am currently responsible for developing generation portfolio plans to serve customers' future energy and capacity requirements. My group also monitors fuel expenses and provides forecasted operational data to various groups within the Company.

I have previously submitted testimony before the Virginia State Corporation Commission ("Commission"), as well as the North Carolina Utilities Commission.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to, and generally support, the pre-filed direct testimony of Staff Witnesses Wayne D. McCoy and John W. Chiles with regard to the Company's decision to retire Yorktown Power Station ("Yorktown") Units 1-2 and Chesapeake Energy Center ("CEC") Units 1-4 by 2015. Additionally, I will respond to the generation-related questions that the Hearing Examiner posed during the public hearing in this case held on January 10, 2013, and raised by the additional studies conducted pursuant to the Hearing Examiner's January 30, 2013 Ruling ("January 30 Ruling"). These questions were primarily related to gas availability and the ability to repower, retrofit or build new generation at Yorktown in combination with a 230 kV alternative to solve violation of mandatory North American Electric Reliability

Corporation ("NERC") Reliability Standards ("NERC Reliability Violations" or "Reliability Violations") .

My testimony will also summarize the options that are available for these units to meet effective and anticipated U.S. Environmental Protection Agency ("EPA") regulations, the process the Company used to examine these options, and the results of the economic analysis that demonstrate that retiring these units by 2015 is in the best interest of customers.

Q. Are you sponsoring any exhibits or schedules with your testimony?

A. Yes, Company Exhibit No. __, GAK, consisting of Rebuttal Schedules 1-3, was prepared under my supervision and is accurate and complete to the best of my knowledge.

Rebuttal Schedule 1 and Extraordinarily Sensitive Rebuttal Schedule 2, together, make up a presentation that was given to the Commission Staff on June 8, 2012 and September 6, 2012 as part of their review of the Company's proposed Project, including the 500 kV overhead Surry-Skiffes Creek line. A similar presentation was also made during the Company's Integrated Resource Planning ("IRP") Stakeholder Review Process meeting on October 19, 2012. My Extraordinarily Sensitive Rebuttal Schedule 3 depicts the generation analysis conducted pursuant to the January 30 Ruling requiring additional studies of generation options at Yorktown. Public versions and Extraordinarily Sensitive versions of my Rebuttal Schedules 2 and 3 are filed under seal pursuant to the September 12, 2012, December 12, 2012 and January 14, 2013 Hearing Examiner's Protective Rulings issued in this proceeding.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. In analyzing effective and anticipated environmental regulations, the Company first conducts extensive studies to estimate their likely impact, compliance dates, and potential effect on existing and future resources. Next, the Company thoroughly examines all possible options for meeting compliance with those regulations, including retrofitting certain units with new environmental equipment, repowering certain units by converting to an alternative fuel source, or retiring certain units in favor of building new generation. As a result of this analysis, the Company has determined that the most cost-effective solution for customers is to retire Yorktown Units 1-2 and CEC Units 1-4, and that the best option for replacing the retired generation is to accelerate the need for the Project to address the NERC Reliability Violations that occur in 2015 and build a new gas-fired combined-cycle outside the Hampton Roads Load Area.

My rebuttal testimony is organized as follows:

I. Generation Analysis of At-Risk Units
II. Retrofit Analysis
III. Repower Analysis
IV. Operating Limitations on Yorktown Unit 3
V. New Generation in Hampton Roads Load Area
VI. Additional Analyses of Generation at Yorktown per January 30 Ruling

I. GENERATION ANALYSIS OF AT-RISK UNITS

Q. Please describe the analysis conducted by the Company to assess anticipated environmental compliance regulations and how they affect the Company's generating resources.

A. As described on pages 3 through 6 of my Rebuttal Schedule 1 and in the rebuttal testimony of Company Witness Pamela Faggert, the EPA has issued a significant number of new regulations that are expected to affect certain units across the Company's fleet of generation resources. These regulations are designed to regulate air, water, and solid waste constituents of the generation fleet. As a result, all of these regulations must be considered when developing a cost-effective, reliable Integrated Resource Plan ("Plan").

When analyzing environmental compliance regulations, the Company first extensively studies the various regulations to estimate their likely impact, compliance dates, and potential effect on existing and future resources. Next, the Company examines each of its existing generation resources to determine what, if any, changes would be required to meet anticipated regulations. This change could include retrofitting certain units with new environmental equipment ("retrofit") or repowering certain units by converting to a natural gas, oil, or biomass fuel source ("repower"). Finally, the potential options to comply with the anticipated regulations are analyzed using the Strategist model to determine the lowest reasonable cost and most reliable plan to meet anticipated regulations. Strategist is a state-of-the-art portfolio optimization tool that is used by electric utilities to help identify economical long-term resources to meet future customer capacity and energy needs by simulating real-world operation of a utility system in a power market. This is the same tool used in the Company's system-wide Plan, as well as in other generation-related certificate proceedings and is familiar to the Commission and Commission Staff.

Q. Was the retirement analysis included as part of the Company's recent Plans?

A. Yes. The outcome of this analysis became the basis of the unit retirements included in the Company's 2011 and 2012 Plans.

In the 2011 Plan, the Company announced the retirement of Yorktown Unit 1 (2015), CEC Units 1-2 (2015), and CEC Units 3-4 (2016). Furthermore, it included the repower of Bremo Units 3-4 (2014) from coal to natural gas, Yorktown Unit 2 (2015) from coal to gas and oil, and three coal-fired generating stations Altavista, Hopewell, and Southampton (2013) to biomass. Finally, it included retrofits to the Company's two heavy-oil units, Yorktown Unit 3 and Possum Point Unit 5, in 2015.

In December 2011, upon updating its analysis, the Company decided to also retire Yorktown Unit 2 by 2015 instead of repowering the unit to natural gas and oil. This update occurred after the Company concluded additional studies regarding the availability of gas, cost of repowering and operating Yorktown Unit 2 on gas and oil, and the potential shared costs with Yorktown Unit 3. It became clear that the economics no longer supported the gas/oil conversion of the unit.

In 2012, the Company updated its analysis in preparation for filing its 2012 Plan. The 2012 Plan includes the retirement of Yorktown Units 1-2 and CEC Units 1-4 by 2015. The repower of Bremo, Altavista, Hopewell, and Southampton are still included in the 2012 Plan, which was filed in Case No. PUE-2012-00099 and accepted for filing by the Commission's October 16, 2012 Final Order. The retrofit of Yorktown Unit 3 has been delayed until 2018 based on current estimates of environmental regulation dates. Figure 1 provides a summary of the 2012 Plan.

Figure 1: 2012 Integrated Resource Plan

2012 IRP				
Year	**New**	**Retrofit**	**Repower**	**Retire**
2013	solar community		**AV – bimoass** **HW – biomass** **SH – biomass**	
2014	municipal solid waste		**BR3 – gas** **BR4 – gas**	
2015	CC (Warren)	**PP5 – SNCR**		**CEC 1-4** **YT 1&2**
2016	CC (Brunswick)			
2017				
2018		**YT3 – SNCR**		
2019	CC1			
2020	solar tag			
2021	CT1			
2022	CT2 Wind1			
2023	Wind2			
2024	North Anna 3 Wind3			
2025				
2026				
2027				

Key: Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or report by natural gas; Retire: Remove a unit from service; AV: Altavista; BR: Bremo; Brunswick: Brunswick County Power Station; CEC: Chesapeake Energy Center Unit; CC: Combined-Cycle; CT: Combustion Turbine (2 units); HW: Hopewell; North Anna 3: North Anna Unit 3; PP5: Possum Point 5; SH: Southampton; SNCR: Selective Non-Catalytic Reduction; Solar Community: Community Solar Power Program; Warren: Warren County Power Station; Wind: Onshore Wind; YT: Yorktown Unit.

(See Figure 1.4.1 on page 6 of the Company's 2012 Plan filed in Case No. PUE-2012-00099.)

Q. Please clarify what you mean when you say Yorktown Units 1-2 and CEC Units 1-4 will be retired "by 2015"?

A. As noted above, all of these units are scheduled to retire by 2015, which corresponds to the compliance date of the EPA's Mercury and Air Toxics Standards ("MATS"). The final MATS rule was issued in December 2011 and has a compliance date of April 16, 2015. For modeling purposes, the 2012 Plan includes retirement dates for Yorktown Units 1-2 and CEC Units 1-4 of December 31, 2014. Although an exact date has not yet been determined, current plans reflect that these units will not be available for the 2015 summer peak season.

Q. Which unit retirements create the need for the Project?

A. As Company Witness Peter Nedwick describes further, there is a need for the Project in 2015 if *either* Yorktown Unit 1 or 2 is retired. As noted above, both of these units are scheduled to retire by 2015.

Yorktown Unit 3, an 818 MW heavy-oil fired unit, will remain in service, but will have operations limited by an 8% capacity factor in order to achieve MATS compliance. This operating condition is discussed in further detail in the pre-filed rebuttal testimony of Company Witness Faggert.

II. RETROFIT ANALYSIS

Q. Please describe the retrofit equipment needed to bring Yorktown Units 1 and 2 into compliance with anticipated regulations.

A. As I noted previously, the Company first reviewed all of its generating fleet to assess what environmental equipment would be necessary to bring each unit into compliance.

Figure 2 shows the necessary environmental equipment that each coal or heavy-oil fired unit would require.

Figure 2: Retrofits Required

	SO_2/MATS/PM				NO_x		Hg		316 (b)		Eff	CCB
Unit	Dry Scrubber Installation	Wet Scrubber Installation	DSI (Sodium Bicarbonate)	Baghouse	SCR	SNCR	ACI	Calcium Bromide	Intake Screens / VSD	Closed Cycle Cooling	Water Treatment Upgrades	CCB Convert To Dry Ash
BR - Bremo 3 & 4									X		X	
CEC - Chesapeake 1 & 2	X			X	X				X	X	X	X
CEC - Chesapeake 3 & 4	X			X					X	X	X	X
CH - Chesterfield 3,4, 5 & 6									X		X	X
CL - Clover 1 & 2											X	
ME - Mecklenburg 1 & 2											X	
MS - Mount Storm 1, 2, & 3											X	
PP - Possum Point 3, 4 & 6									X		X	
PP - Possum Point 5						X					X	
YT - Yorktown 1 & 2	X			X	X				X	X	X	
YT - Yorktown 3						X			X		X	

Note: Yorktown Unit 3 would also likely require a baghouse and closed cycle cooling equipment if runtime exceeds capacity factor limitation.

As shown in Figure 2, Yorktown Units 1 and 2 would require a Dry Scrubber, Baghouse, Selective Catalytic Reduction ("SCR"), Water Intake Screens, Variable Speed Drives ("VSD"), and Closed Cycle Cooling in order to continue operating on coal. The CEC units would require similar equipment, with the exception of CEC Units 3-4, which already have an SCR.

Q. Has the Company estimated the cost of environmental retrofits for these units?

A. Yes. Extraordinarily Sensitive Figure 3 shows the estimated costs of these retrofits.

Yorktown Units 1 and 2 have a combined expected cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** and CEC Units 1-4 have a combined expected cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted] **[END EXTRAORDINARILY SENSITIVE]**. Combined, the cost of environmental retrofits for these six coal units, which total 918 MW, are estimated to be approximately **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]**.

Extraordinarily Sensitive Figure 3: Retrofit Capital Costs

[EXTRAORDINARILY SENSITIVE INFORMATION INDICATED BY GREEN HIGHLIGHTING]

Unit	316 (b) Closed Cycle Cooling (2018-2022)	Other CapEx (2012-2022)	TOTAL CapEx (2012-2022)
BR - Bremo 3 & 4		[redacted]	
CEC - Chesapeake 1 & 2	[redacted]		
CEC - Chesapeake 3 & 4	[redacted]		
CH - Chesterfield 3,4, 5 & 6		[redacted]	
CL - Clover 1 & 2		[redacted]	
ME - Mecklenburg 1 & 2		[redacted]	
MS - Mount Storm 1, 2, & 3		[redacted]	
PP - Possum Point 3, 4 & 6		[redacted]	
PP - Possum Point 5		[redacted]	
YT - Yorktown 1 & 2	[redacted]		
YT - Yorktown 3		[redacted]	
	$761 M	$1,697 M	$2,458 M

To put this in perspective, the Company's proposed Brunswick County combined-cycle generating facility will yield significantly more capacity (1,358 MW nominal) for less capital cost of $1.27 billion or $934/kW. Moreover, the new combined-cycle facility, due to its efficient heat rate and the low cost of natural gas, will run at much higher capacity factors, produce fewer emissions, and yield more fuel savings than these less efficient, 50-year old coal-fired units if they were retrofit. Extraordinarily Sensitive Figure 4 shows the capital cost comparison between retrofitting these coal units with the necessary environmental equipment and a new 3x1 combined-cycle facility.

Extraordinarily Sensitive Figure 4: Capital Cost Comparison

[EXTRAORDINARILY SENSITIVE INFORMATION INDICATED BY GREEN HIGHLIGHTING]

	Capacity (MW)	Capital Cost $ million	$/kW
Yorktown 1-2	323	[redacted]	[redacted]
Chesapeake 1-4	595	[redacted]	[redacted]
Brunswick 3x1 CC	1358	1,269	934

Q. Did the Staff review these cost estimates?

A. Yes. Staff Witness Chiles reviewed the Company's retrofit cost estimates and compared them to industry averages for similar equipment. He concluded on page 28 of his testimony that the Company's costs align closely with typical industry values and, "[t]hus, the cost estimates for either retrofit scenario appear to be reasonable." I would note that the Company's cost estimates are based on the Company's detailed knowledge and operation of these specific units and not based on generic industry averages. Nonetheless, Mr. Chiles offers a useful comparison to validate the Company's cost estimates and concludes that they are reasonable.

III. REPOWER ANALYSIS

Q. Has the Company examined other options for the Yorktown and CEC coal units?

A. Yes, given the high costs of the environmental retrofits, the Company has also examined the possibility of repowering some or all of these units to natural gas. From a capital cost perspective, this option appears to be more favorable. However, currently there is not enough firm gas supply to support year-round operation of gas-fired generation at the Yorktown or CEC sites. Repowering these units to natural gas would require significant expansions to the regional gas supply in order to fuel these stations. In addition to the unfavorable economics of such an expansion, it also could not be completed until 2018, well after the April 2015 MATS compliance date.

Q. Has the Company examined the cost of adding additional gas capacity to the region?

A. Yes. In September 2010, the Company issued a Request for Information ("RFI") to the major gas pipeline companies that could bring additional supply to the region. The purpose of the RFI was to estimate the availability and costs of acquiring firm gas transportation to the CEC, Possum Point, and Yorktown generating sites. For the CEC and Yorktown locations, **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** submitted estimated costs for firm gas transportation. The lowest cost estimated for supplying firm gas transportation for repowering units at the CEC and Yorktown locations was **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** respectively. For comparison purposes, the

Company's proposed Brunswick County combined-cycle project will receive firm gas transportation for approximately **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]**. Extraordinarily Sensitive Figure 5 shows a comparison of the annual costs to provide firm gas capacity to the repower options versus the Brunswick County combined-cycle facility.

Extraordinarily Sensitive Figure 5: Annual Firm Gas Transportation

[EXTRAORDINARILY SENSITIVE INFORMATION INDICATED BY GREEN HIGHLIGHTING]

	Capacity (MW)	Firm Gas Transport $ million/yr	$/kW-yr
Yorktown 1-2	323	[redacted]	[redacted]
Chesapeake 1-4	595	[redacted]	[redacted]
Brunswick 3x1 CC	1358	[redacted]	[redacted]

Additionally, as part of the RFI process **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted] **[END EXTRAORDINARILY SENSITIVE]** to complete the gas capacity expansion to fuel Yorktown. Therefore, if the Company were to pursue this alternative at this time, such an expansion would likely not be available until the 2018 peak season.

Q. Did the Staff review the Company's 2010 RFI and analysis?

A. Yes. Staff Witness Chiles reviewed the Company's 2010 RFI for the gas repowering alternative in that region. He concluded on page 31 of his testimony:

> It does not appear that natural gas pipeline capacity could be constructed in time to meet the fuel requirements for repowered units at Chesapeake or Yorktown. Even without consideration of the capital costs of repowering the generation at Chesapeake and Yorktown, the lowest cost of firm transport for natural gas to the

sites alone would exceed the cost of the cheapest transmission alternative within the near future.

Q. What is the Hampton Roads Crossing ("HRX") pipeline?

A. The HRX pipeline project connects two gas supply sources (Columbia Gas Transmission and Dominion Transmission) within the Virginia Natural Gas, Inc. ("VNG") certificated service territory. Prior to HRX, the VNG natural gas distribution system was divided into two non-contiguous pipeline systems (Southern and Northern) due to the geography of the Hampton Roads harbor. The Southern pipeline served the areas of Norfolk, Virginia Beach, Chesapeake and Suffolk in the South Hampton Roads Load Area. The Northern pipeline served Hampton, Newport News, Poquoson, York, James City, Williamsburg, New Kent, and Charles City on the Peninsula, as well as Hanover and King William Counties, in the North Hampton Roads Load Area.

According to VNG, the HRX pipeline was constructed primarily to increase gas reliability and flexibility on their distribution system, while meeting residential and commercial growth throughout the region.

Q. Could the HRX pipeline be used to fuel CEC and/or Yorktown generating stations?

A. The HRX pipeline project was completed in January 2010 **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]**, the HRX pipeline project did not by itself add sufficient capacity on VNG's system to meet the firm natural gas supply requirements of a large natural gas-fired power generating station. Additional infrastructure improvements on the interstate pipeline system upstream of the VNG system are required to serve these generating units. Therefore, the Company concluded that adequate firm gas supply does not exist to support a repower of the generating units in order to alleviate the need for the Project.

IV. OPERATING LIMITATIONS ON YORKTOWN UNIT 3

Q. Since Yorktown Unit 3 is not expected to retire, could this unit provide reliable generation to the Hampton Roads Load Area?

A. No, for several reasons. First, as I mentioned earlier and as further detailed by Company Witness Faggert, Yorktown Unit 3 will be limited to an 8% capacity factor beginning in 2015 to comply with MATS. As an alternative to accepting the operation limit, the Company could retrofit this unit with additional environmental equipment at a capital cost of approximately **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted] **[END EXTRAORDINARILY SENSITIVE]**. This would include adding a baghouse, water intake structures, and closed cycle cooling equipment. Similar to the other retrofit options discussed earlier, this is not a cost-effective solution.

Second, due to the design of Yorktown Unit 3, it would be difficult to operate this unit as a reliability unit. As a large heavy-oil unit, this unit has long ramp rates and is not capable of quickly cycling to meet local reliability constraints.

Finally, and perhaps most importantly, Yorktown Unit 3 is one of the most expensive units in the Company's generation fleet to operate. It is a peaking resource that is typically only used during the very hottest days with high loads. Having to operate this unit on any day but the peak days will have a significant impact to customer fuel costs. For context, on an average day in 2012, operating Yorktown Unit 3 would have increased customer fuel costs by approximately $2.5 million per day versus market purchases. For this reason, it would not be cost-effective for customers to be in a position to have to operate this unit for local reliability.

V. NEW GENERATION IN HAMPTON ROADS LOAD AREA

Q. Did the Company consider siting new generation in the Hampton Roads Load Area to replace the retired generating capacity?

A. Yes. After the economic analyses determined that retiring the coal units would be the most cost-effective solution for customers, the Company considered how to best replace them with new generation. The Company examined multiple sites for new generation, including in the Hampton Roads Load Area.

The Company first considered generation options such as new combined-cycle, combustion turbine, and coal generation. New gas-fired generation in the region is challenged by the same firm gas supply limitations that make repowering the existing units not cost effective or able to be completed by 2015. New coal units without carbon capture compatibility would be unable to comply with the EPA's New Source Performance Standards ("NSPS"), proposed on April 13, 2012. Additionally, the Company considered other small-scale generation resources, both dispatchable and non-dispatchable. Resources such as biomass, wind, and solar were not sited in this region on the basis of their relative cost and site availability.

Therefore, it was determined that the best option for replacing the retired generation is to accelerate the need for Skiffes to address the NERC Reliability Violations that occur in 2015 and build a new gas-fired combined-cycle outside the Hampton Roads Load Area.

The Company has filed an application with the Commission in Case No. PUE-2012-00128, for such a facility – the proposed Brunswick County combined-cycle project.

Q. Did the Company include the cost of transmission upgrades in its retirement analysis?

A. Yes. As part of its Strategist modeling in the IRP process, the Company included estimates of the transmission upgrades that would be required if the Yorktown and/or CEC units retired. These costs are summarized on page 3 of my Extraordinarily Sensitive Rebuttal Schedule 2.

Q. Has the Company considered retiring only some of the units and retrofitting or repowering others?

A. Yes. As I described previously, the original analysis presented in the 2011 Plan included the retirement of Yorktown Unit 1 and the repower of Yorktown Unit 2 to gas and oil. Even under this scenario, the Project would still be required in 2015, and I understand this was the generation combination that was analyzed at the time the Project's need date was accelerated to 2015. Nonetheless, we have fully evaluated retrofit and repower options on individual units and combinations of units, where applicable, and still conclude that retiring all six units provides the lowest-cost plan for customers.

VI. ADDITIONAL ANALYSES OF GENERATION AT YORKTOWN PER JANUARY 30 RULING

Q. Did you conduct any additional studies of the possibility of retaining or adding new generation at Yorktown in combination with 230 kV transmission projects?

A. Yes, I did. Pursuant to the January 30 Ruling and subject to compliance with state and federal codes and standards of conduct, I was asked by Company Witness Nedwick to analyze the costs of retaining or providing new generation in different amounts in 2015 and 2021 in order to make 230 kV alternatives able to solve the 2015 and 2021 Reliability Violations. My Extraordinarily Sensitive Rebuttal Schedule 3 provides the results of this analysis.

Q. What are the assumptions incorporated in your Extraordinarily Sensitive Rebuttal Schedule 3?

A. First, it should be noted that the dollars presented in Extraordinarily Sensitive Rebuttal Schedule 3 are incremental to the expenditures already embedded in the 2012 Plan. For example, Yorktown 3 already has costs allocated for an SNCR in 2018 so these dollars are not included again. Likewise, the 2012 Plan already identifies a new 3x1 combined-cycle (2019) and combustion turbines (2021, 2022), but which are not located in the Hampton Roads Load Area. Therefore, I have only included the incremental costs of relocating these options to Yorktown in my analysis.

Second, generation options requiring gas capacity expansion, designated as "FT" in Extraordinarily Sensitive Rebuttal Schedule 3, are not available until 2018 for the reasons explained earlier. Therefore, these options are not available to resolve NERC Reliability Violations occurring in 2015.

Third, for the reasons described earlier and in Company Witness Faggert's rebuttal testimony, the analysis did not consider Yorktown 3 to be a viable solution to NERC Reliability Violations without spending the necessary capital to eliminate its 8% capacity factor limitation.

Finally, the analysis only considered the incremental capital and firm gas transportation costs required to provide the Yorktown generation. It did not consider the future fuel costs and benefits of one option against the other or the additional labor and material costs required to operate these units because at this time it is not known precisely how often these units would be required to run for reliability under the various scenarios. These are vital considerations if the Company were to pursue these generation options at Yorktown.

Q. Please discuss your findings for Alternative A.

A. For Alternative A, as that option is defined in Company Witness Scot C. Hathaway's rebuttal testimony, I was asked to determine the lowest cost of providing 1,008 MW and 1,449 MW of Yorktown generating capacity in 2015 and 2021, respectively. Furthermore, in 2021, the generation must come from two different units where the outage of any one unit would not leave less than 87 MW of generation available for reasons discussed in Company Witness Nedwick's rebuttal testimony.

To meet the 2015 requirement, this would require repowering Yorktown Unit 2 to gas and oil (157 MW) and retrofitting Yorktown Unit 3 with a baghouse (818 MW) to comply with MATS. The total cost for these generation options is $350 million and provides 975 MW of unrestricted generation capability. To meet the 2021 generation requirement, an additional cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** is incurred to comply with anticipated § 316(b) regulations at Yorktown Unit 2 and **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** in additional firm gas transportation costs to relocate the planned 2019 combined-cycle to the Hampton Roads Load Area. Therefore, the total generation cost would be $927 million in combination with Alternative A to address the NERC Reliability Violations in 2015 and 2021.

Q. Please discuss your findings for Alternative B.

A. For Alternative B, as that option is defined in Company Witness Hathaway's rebuttal testimony, I was asked to determine the lowest cost of providing 159 MW and 551 MW of Yorktown generation in 2015 and 2021, respectively. Furthermore, in 2021 the generation must come from two different units where the outage of any one unit would not leave less than 27 MW of generation available for reasons discussed in Company Witness Nedwick's rebuttal testimony.

To meet the 2015 requirement, this would require repowering Yorktown Unit 2 to gas and oil (157 MW) at a cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]**. To meet the 2021 generation requirement, an additional cost of **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]**[END EXTRAORDINARILY SENSITIVE]** is incurred to comply with anticipated § 316(b) regulations at Yorktown Unit 2 and **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** in additional firm gas transportation costs to relocate the planned 2019 combined-cycle to the Hampton Roads Load Area. Therefore, the total generation cost would be $677 million in combination with Alternative B to address the NERC Reliability Violations in 2015 and 2021.

Q. Please discuss your findings for Alternative C.

A. For Alternative C, as that option is defined in Company Witness Hathaway's rebuttal testimony, I was asked to determine the lowest cost of providing 552 MW and 505 MW of Yorktown generation in 2015 and 2021, respectively. Furthermore, the generation must come from two different units where the outage of any one unit would still leave at least 56 MW of generation available in 2015 and 139 MW of generation available in 2021 for reasons discussed in Company Witness Nedwick's rebuttal testimony.

To meet the 2015 requirement, this would require repowering Yorktown Unit 2 to gas and oil (157 MW) and retrofitting Yorktown Unit 3 with a baghouse (818 MW) to comply with MATS. The total cost for these generation options is $350 million and provides 975 MW of unrestricted generation capability. To meet the 2021 generation requirement, an additional cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** is incurred to comply with anticipated § 316(b) regulations at Yorktown Unit 2 and **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** in additional firm gas transportation costs to relocate the planned 2019 combined-cycle to the Hampton Roads Load Area. Therefore, the total generation cost would be $927 million in combination with Alternative C to address the NERC Reliability Violations in 2015 and 2021.

Q. Please discuss your findings for the Stand-Alone Generation Option.

A. For the Stand-Alone Generation Option, as that option is defined in Company Witness Hathaway's rebuttal testimony, I was asked to determine the lowest cost of providing 620 MW of Yorktown generation in both 2015 and 2021. Furthermore, the generation must come from two different units where the loss of any one unit would still leave at least 295 MW of generation available in either year for reasons discussed in Company Witness Nedwick's rebuttal testimony.

To meet the 2015 requirement, this would require retrofitting Yorktown Unit 1 (159 MW) on coal, repowering Yorktown Unit 2 to gas and oil (157 MW), and retrofitting Yorktown Unit 3 with a baghouse (818 MW) to comply with MATS. The total cost for these generation options is $633 million and provides 1,134 MW of unrestricted generation capability with the required minimum unit capacity. To meet the 2021 generation requirement, an additional cost of **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** is incurred to comply with anticipated § 316(b) regulations at Yorktown Units 1 and 2 and **[BEGIN EXTRAORDINARILY SENSITIVE]**[redacted]**[END EXTRAORDINARILY SENSITIVE]** in additional firm gas transportation costs to relocate the planned 2019 combined-cycle to the Hampton Roads Load Area. Therefore, the total generation cost would be $1,345 million for a Stand-Alone Generation Option to address the NERC Reliability Violations in 2015 and 2021.

Q. Did you analyze any other Yorktown generation scenarios?

A. Yes. I was also asked to determine the lowest cost of retaining both Yorktown Units 1 and 2, either by repower or retrofit, thru 2023, for purposes of the Alternative C (transmission only) analysis.

To meet the 2015 requirement, this would require retrofitting Yorktown Unit 1 (159 MW) on coal and repowering Yorktown Unit 2 to gas and oil (157 MW). Yorktown Unit

3 can comply with MATS by limiting its capacity factor to 8% and would require no incremental capital. The total cost for these generation options is $383 million and provides 316 MW of unrestricted generation capability. The units would then require Closed Cycle Cooling to meet the anticipated § 316(b) regulations. The total cost including 316(b) compliance for these generation options is $ 652 million and provides 316 MW of unrestricted generation capability.

Q. What do you conclude from a generation perspective with regard to these Additional Analyses?

A. None of these generation combinations were selected in the 2012 Plan based on their cost-effectiveness. In other words, it is more cost-effective for the Company to build new generation at other site locations, as it is doing through pursuit of its application to construct its proposed Brunswick County combined-cycle project, than it is to retrofit or repower these units in the combinations I set forth above. The analysis I present in my Rebuttal Schedule 3 was conducted under the premise that generation *must* be sited at Yorktown and I was asked to find the lowest capital cost combination for these resources at the MW amounts determined by the transmission planning group. In addition to the higher capital costs, this analysis does not provide the increased fuel, emissions, and Operations and Maintenance costs associated with these combinations of resources. The results of these Additional Analyses from a generation perspective confirm and reinforce the results of the analyses conducted by the Company through the 2011 and 2012 Plans.

Q. Please summarize your overall conclusions regarding the need to retire the Yorktown and Chesapeake coal units by 2015.

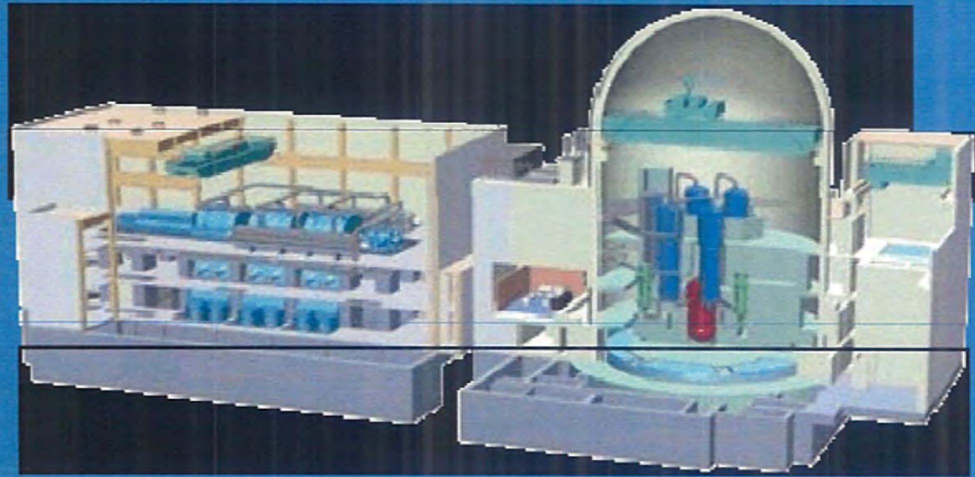
A. The Company has thoroughly examined all possible options for meeting effective and anticipated EPA regulations. These options include:

- Retrofitting all or some of the coal units with the necessary environmental equipment;
- Repowering all or some of the coal units to alternative fuels such as natural gas, oil, or biomass;
- Retiring the coal units and building new generation in the Hampton Roads Load Area; and
- Retiring the coal units and building new generation in more cost-effective locations.

The analysis conducted for the 2012 Plan shows very clearly that retiring the Yorktown and CEC units and accelerating the need for the Project to 2015 provides the most cost-effective solution for customers.

Q. Mr. Kelly, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.



IRP - Generation Process including an Environmental Regulation Discussion

Sep 6, 2012

Dominion

Objective / Agenda

Objective:

Review the process that determined when investments in environmental controls on existing generating units is in the best interest of customers.

Agenda:

- Environmental Regulations (effective and anticipated as currently detailed and understood)
- Control Equipment
- Process/methodology
- Detailed Example of Analysis
- Supplemental (contains Confidential and Extraordinarily Sensitive data)
  - Unit level Control Capital Expenses (CapX)
  - Infrastructure (Gas / Electric) CapX
  - Option comparisons

Code of Conduct Sensitivity

Please do not discuss any transmission specific information in this meeting until the end of the presentation (after generation employees leave).

Environmental Regulations

❑ Mercury & Air Toxics Standards (MATS)

- **Proposed rule issued:** March 2011
- **Final rule issued**: December 2011
- **Compliance date:** April 16, 2015
- **Description**
  - Regulates emissions of toxics from coal and oil units greater than 25 megawatts (MW)
  - Sets emission limits for particulate matter, metals, and acid gases.
  - No trading, allowances, or averaging allowed between facilities
  - Rule allows for a 1-year extension for certain situations including transmission upgrades to maintain reliability.

❑ National Ambient Air Quality Standard (NAAQS) for Sulfur Dioxide (SO_2)

- **Final rule issued:** June 2010
- **Compliance date:** 2018
- **Description**
  - Established a new 1-hour NAAQS at a level of 75 parts per billion (ppb).
  - Existing sources could be impacted if they are implicated as causing or contributing to a modeled violation of the standard through refined modeling that is expected to be required to evaluate compliance with the standard or in another source's Prevention of Significant Deterioration (PSD) permit modeling demonstration.
  - Could require scrubbers, fabric filters, Dry Sorbent Injection (DSI) lite at some facilities.

Environmental Regulations
cont'd

- **National Ambient Air Quality Standard (NAAQS) for Ozone**
  - **Proposed rule issued:** Expected October 2013
  - **Final rule issued:** Expected July 2014
  - **Compliance date:** Expected 2017-2018
  - **Description**
    - Driver for additional Nitrogen Oxide (NO_x) controls for facilities in ozone non-attainment areas.
    - In the interim, Environmental Protection Agency (EPA) is implementing the current 75-ppb standard.
    - Final designations and nonattainment classifications for 75-ppb standard were issued on May 2, 2012. Northern VA region designated nonattainment; remainder of state designated attainment.

- **Clean Air Transport Rule (CATR), now known as the Cross State Air Pollution Rule (CSAPR)**
  - **Proposed rule issued:** July 2010
  - **Final rule issued:** July 2011
  - **Compliance dates:** January 1, 2012 for SO_2 and NO_x. Stricter SO_2 January 1, 2014.
  - **Description**
    - Requires reductions in SO_2 and NO_x emissions from fossil fuel-fired electric generating units of 25 MW or greater.
    - Some ability to use allowance purchases for compliance.

DC Circuit vacated CSAPR on Aug 21, 2012
CAIR remains in effect

Environmental Regulations
cont'd

- **Clean Air Interstate Rule (CAIR)**
  - **Final rule issued:** May 2005
  - **Compliance dates:** January 1, 2009 for NO_x (Ozone and Annual), January 1, 2010 for SO_2 and January 1, 2015 for stricter NO_x (Ozone and Annual) and SO_2.
  - **Description**
    - Rule stays in place based upon CSAPR being vacated in August 2012
    - Requires reductions in SO_2 and NO_x emissions from fossil fuel-fired electric generating units of 25 MW or greater.
    - Cap and trade program with full use of allowances.

- **Greenhouse Gas (GHG) New Source Performance Standards (NSPS)**
  - **Proposed rule issued:** March 2012 -- rule is effective when proposed
  - **Final rule issued:** To Be Determined
  - **Compliance date:** April 13, 2012 (date proposal was published in *Federal Register*)
  - **Description**
    - Rule establishes CO_2 standard for new fossil-fired electric generating units larger than 25 MW.
    - Rule does not apply to simple-cycle combustion turbines or biomass units.
    - Timeline for rules for modified and existing sources uncertain.

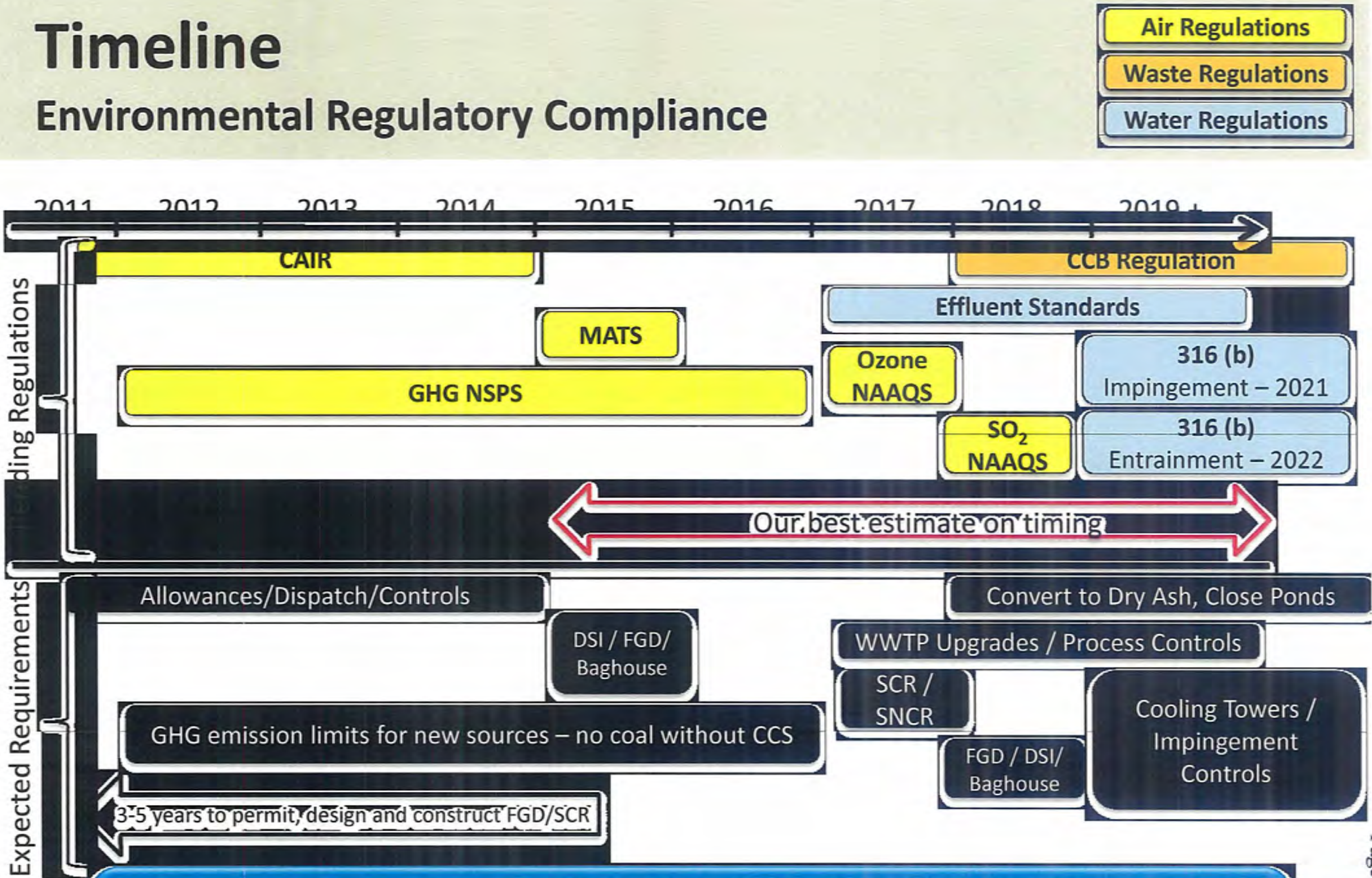
- **Federal Carbon Dioxide (CO_2) Regulations**
  - Cap and trade starting in 2023
  - GHG tailoring rule and Greenhouse Gas New Source Performance Standard effective now

Environmental Regulations
cont'd

- **Coal Combustion Byproducts (CCBs)**
  - **Proposed rule issued:** May 2010
  - **Final rule issued:** Expected 2013
  - **Compliance date:** 2018 convert to dry ash, 2020 close wet ash ponds
  - **Description**
    - EPA is proposing to regulate ash, either as a hazardous or non-hazardous waste.
    - Major impacts include the potential phase-out of surface impoundments, moving to dry handling of ash, and increased costs for handling and disposal.
- **Clean Water Act 316(b)**
  - **Proposed rule issued:** April 2011
  - **Final rule issued:** Expected June 2013
  - **Compliance date:** 8 years for impingement controls (2021), entrainment (approximately 2022)
  - **Description**
    - Variable Speed Drive (VSB) / Screens: 2015 → 2020 plus fish returns
    - Cooling towers possibly required at Yorktown and Chesapeake Energy Center in 2022
- **Effluent Discharges**
  - **Proposed rule issued:** Expected November 2012
  - **Final rule issued:** April 2014
  - **Compliance date:** 2017 - 2019
  - **Description**
    - Water treatment facilities could be needed at a number of plants.

Timeline

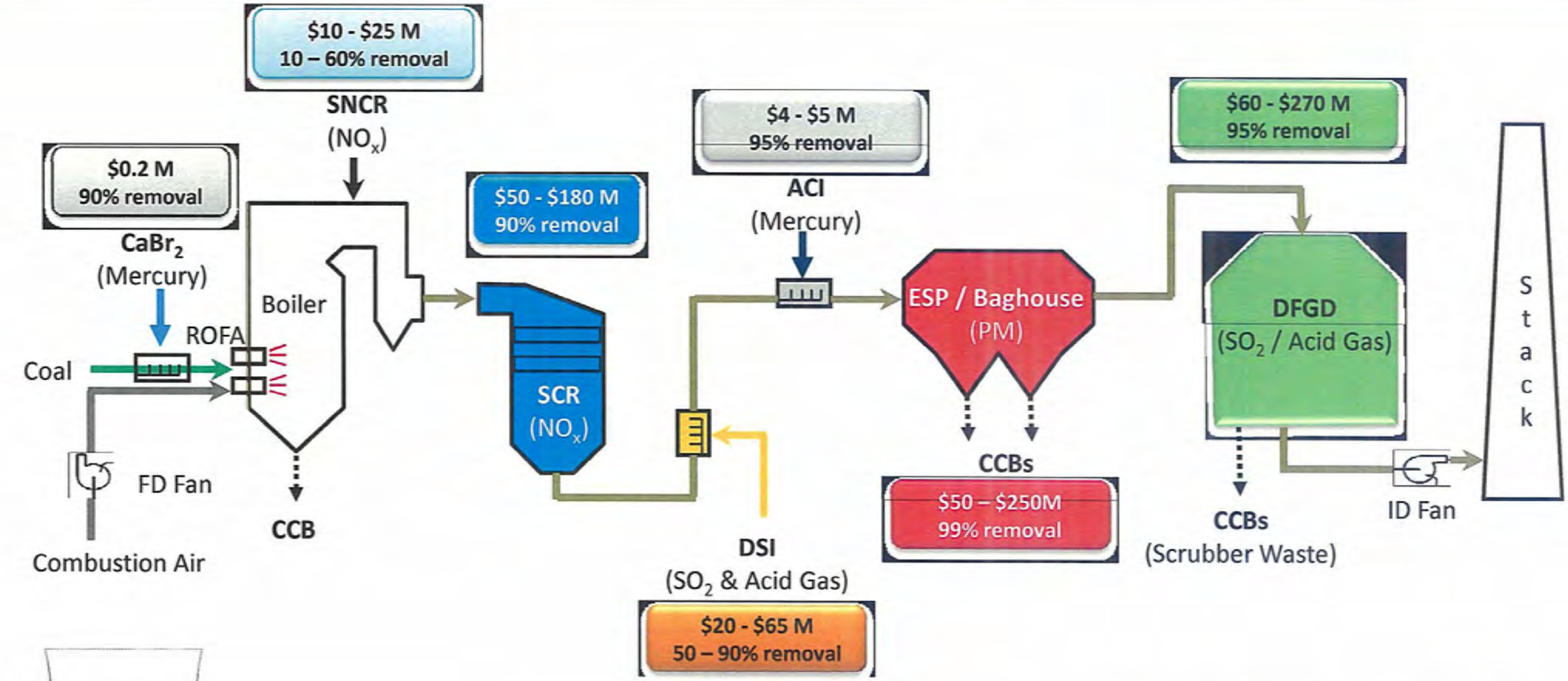
Environmental Regulatory Compliance

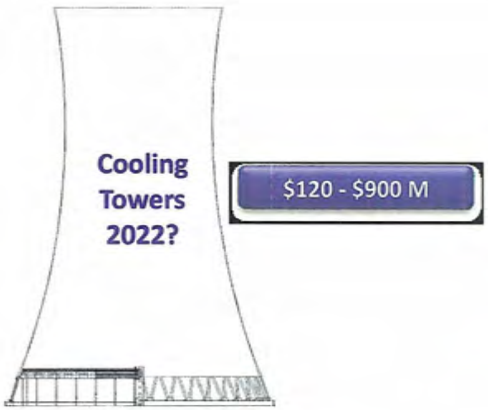


Environmental regulations are affecting fossil generation, primarily coal.
Bottom line: timing is in flux, but coal units would require scrubbers or DSI (SO_2, Hg) and potentially SCRs (NO_x), baghouses (Hg, Ash), changes to ash handling practices, and water intake improvements and possibly cooling towers (Water).

Environmental Control Equipment

Typical Coal Plant





- Coal
- $CaBr_2$ – Calcium Bromide
- Flue Gas
- DSI – Dry Sorbent Injection
- ACI – Activated Carbon Injection
- CCB – Coal Combustion By-Products

DFGD – Dry Flue Gas Desulfurization
ESP – Electrostatic Precipitator
FD – Forced Draft
ID – Induced Draft
NO_x – Nitrogen Oxide
PM – Particulate Matter
ROFA – Rotating Overfire Air
SO_2 – Sulfur Dioxide
SCR – Selective Catalytic Reduction
SNCR – Selective Non-Catalytic Reduction

Existing Resources

Retrofits Required (Environmental Impacts)

Large CapX
- Scrubber
- Baghouse
- SCR
- ~~Cooling Tower~~

Equipment on top

Units on left

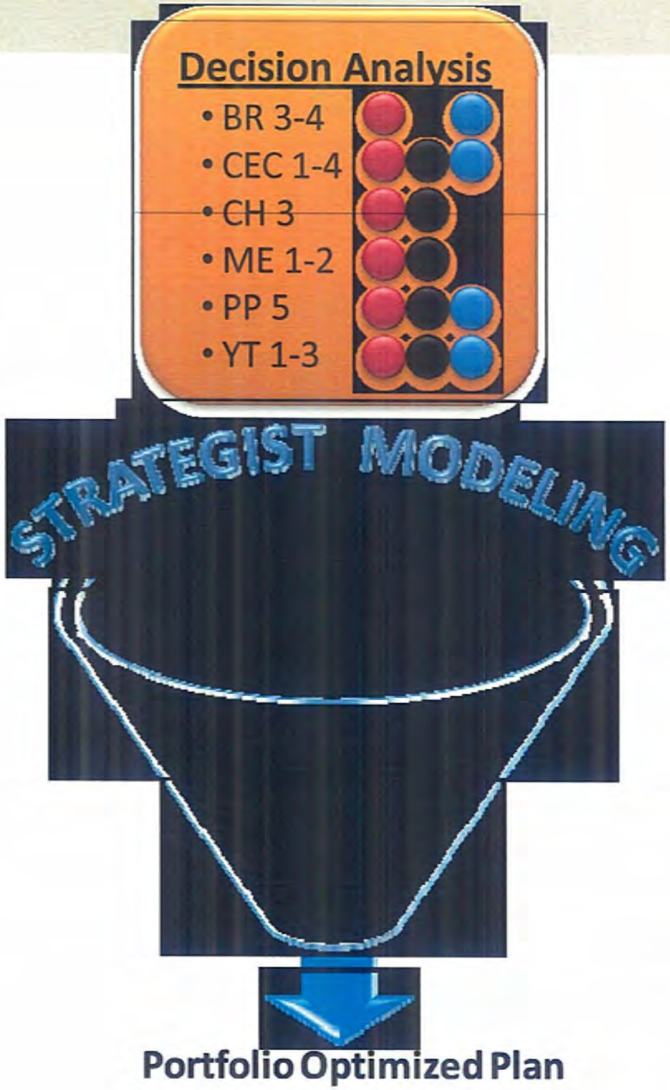
Unit	Dry Scrubber Installation	Wet Scrubber Installation	DSI (Sodium Bicarbonate)	Baghouse	SCR	SNCR	ACI	Calcium Bromide	Intake Screens / VSD	Closed Cycle Cooling
BR - Bremo 3 & 4									X	
CEC - Chesapeake 1 & 2	X			X	X				X	X
CEC - Chesapeake 3 & 4	X			X					X	X
CH - Chesterfield 3,4, 5 & 6									X	
CL - Clover 1 & 2										
ME - Mecklenburg 1 & 2										
MS - Mount Storm 1, 2, & 3										
PP - Possum Point 3, 4 & 6									X	
PP - Possum Point 5						X				
YT - Yorktown 1 & 2	X			X	X				X	X
YT - Yorktown 3						X			X	

* Blue Sheet Data 6-25-2012

Chesapeake & Yorktown coal units require significant additional equipment for compliance

Existing Generation Analysis

- Environmental Compliance
  - limited controlled units
  - Small coal, heavy oil
- Available options
  - Retrofit
  - Repower
  - Retire and replace with:
    - New generation (CC, CT, etc...)
    - Demand Side Management
    - Market purchases
- Two major capital intensive periods
  - 2015 (multiple Air requirements)
  - 2022 (Water requirements)



Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 1
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Decision Analysis

Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

Two major spend periods: 2015 and 2022

1. 2015: Dry Scrubber/BH ($130M) + SCR ($120M) if on coal **or** Gas Repower ($50M) **or** Retire
2. 2022: Cooling Towers ($170M) if on coal/gas **or** Retire

Retrofit	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Dry Scrubber / BH (SO_2)	2015	2012			$130M									
SCR (NO_x)	2018	2014					$120M							
Dry Bottom Ash (CCB)	2017	2014					$10M							
Water Treatment	2017	2014					$20M							
VSD/Screens	2020	2017								$10M				
Cooling Tower	2022	2018										$170M		
Dollar Spend ($M)	$460		**$1**	**$25**	**$83**	**$90**	**$28**	**$17**	**$4**	**$6**	**$41**	**$62**	**$49**	**$3**

Repower	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas Conversion	2015	2013				$50M + gas FT								
VSD/Screens	2020	2017								$10M				
Cooling Tower	2022	2018										$170M		
Dollar Spend ($M)	$230 + gas FT		**$0**	**$0**	**$12**	**$32**	**$6**	**$0**	**$3**	**$6**	**$42**	**$62**	**$49**	**$3**

Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 1
Page 11 of 23

Decision Analysis
Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

2015: Dry Scrubber/BH ($130M) + SCR ($120M) if on coal

1 **Retire in 2022, lower expenses**

Retrofit	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Dry Scrubber / BH (SO_2)	2015	2012			$130M									
SCR (NO_x)	2018	2014						$120M						
Dry Bottom Ash (CCB)	2017	2014					$10M							
Water Treatment	2017	2014						$20M						
VSD/Screens	2020	2017								$10M				

12

Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 1
Page 12 of 23

Decision Analysis

Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

2015: Dry Scrubber/BH ($130M) + SCR ($120M) if on coal

2022: Cooling Towers ($170M) if on coal

2 Extend life, additional environmental expenses

Retrofit	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Dry Scrubber / BH (SO_2)	2015	2012			$130M									
SCR (NO_x)	2018	2014					$120M							
Dry Bottom Ash (CCB)	2017	2014					$10M							
Water Treatment	2017	2014					$20M							
VSD/Screens	2020	2017								$10M				
Cooling Tower	2022	2018										$170M		
Dollar Spend ($M)	$460													

Decision Analysis

Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

2015:

3 **Retire in 2022, lower expenses**

Gas Repower ($50M)

Repower	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas Conversion	2015	2013			$50M + gas FT									
VSD/Screens	2020	2017							$10M					

Decision Analysis

Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

2015: Gas Repower ($50M)

2022: Cooling Towers ($170M) if on gas

4 **Extend life, additional environmental expenses**

Repower	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas Conversion	2015	2013				$50M + gas FT								
VSD/Screens	2020	2017								$10M				
Cooling Tower	2022	2018										$170M		
Dollar Spend ($M)	$230 + gas FT													

Decision Analysis

Small Coal Unit Example

Environmental Equipment

Current: ESP, ROFA

Future: Dry Scrubber/Baghouse (BH), SCR, Dry Bottom Ash, Water Treatment, VSD/Screens, Cooling Tower

Key Drivers

2015: Retire

2022: Retire

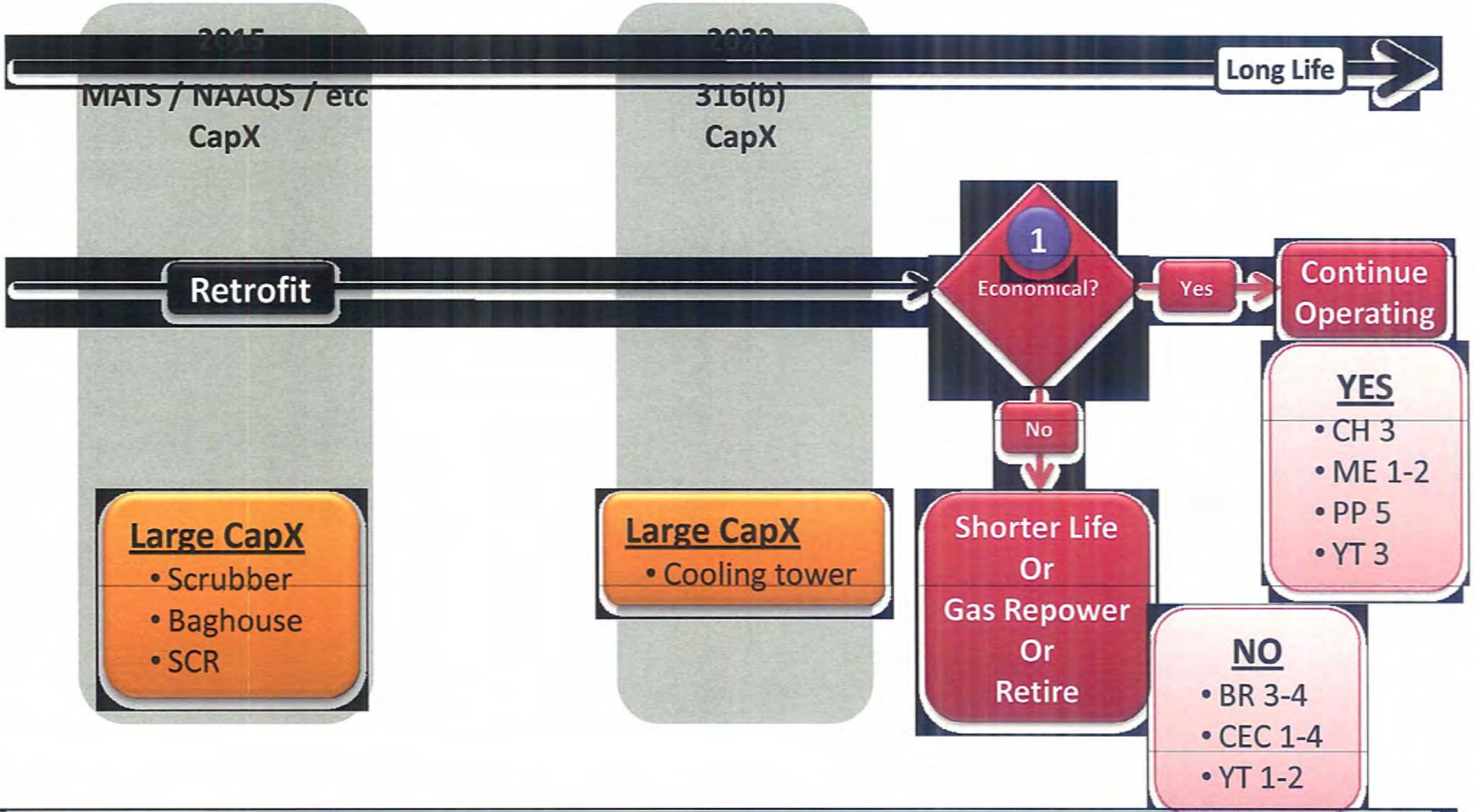
5 **Retire 2015, Brownfield & Transmission Expenses but no environmental capx**

Retrofit	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Dry Scrubber / BH (SO_2)	2015	2012			$130M									
SCR (NO_x)	2018	2014					$120M							
Dry Bottom Ash (CCB)	2017	2014					$10M							
Water Treatment	2017	2014					$20M							
VSD/Screens	2020	2017								$10M				
Cooling T[illegible]	[illegible]	[illegible]										$170M		
Dollar Spend ($M)	$460													

Repower	Date Needed	Start Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas Conversion	2015	2013				$50M + gas FT								
VSD/Screens	2020	2017								$10M				
Cooling Tower	[illegible]	[illegible]										$170M		
Dollar Spend ($M)	$230 + gas FT													

Decision Analysis

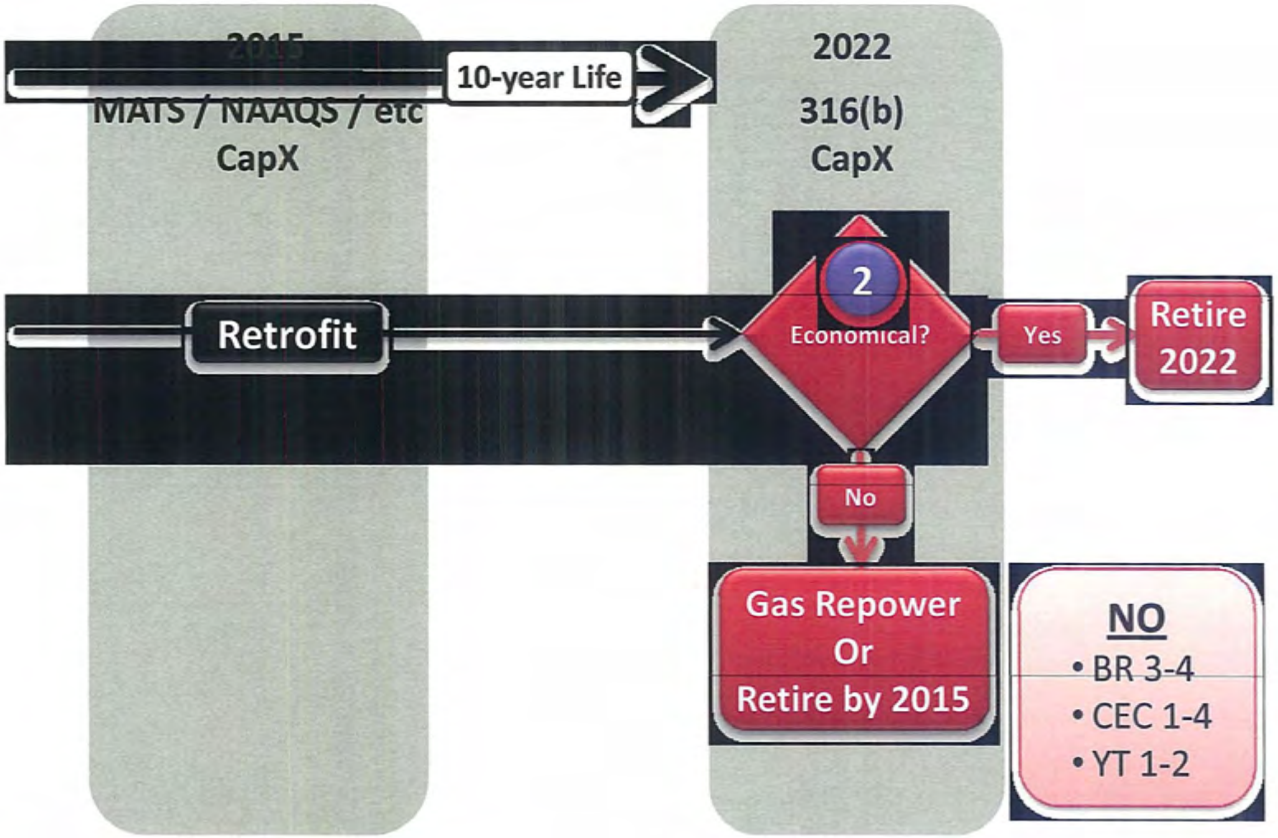
Coal-fired generator



Long life, included all CapX required to meet proposed rules

Decision Analysis (continued)

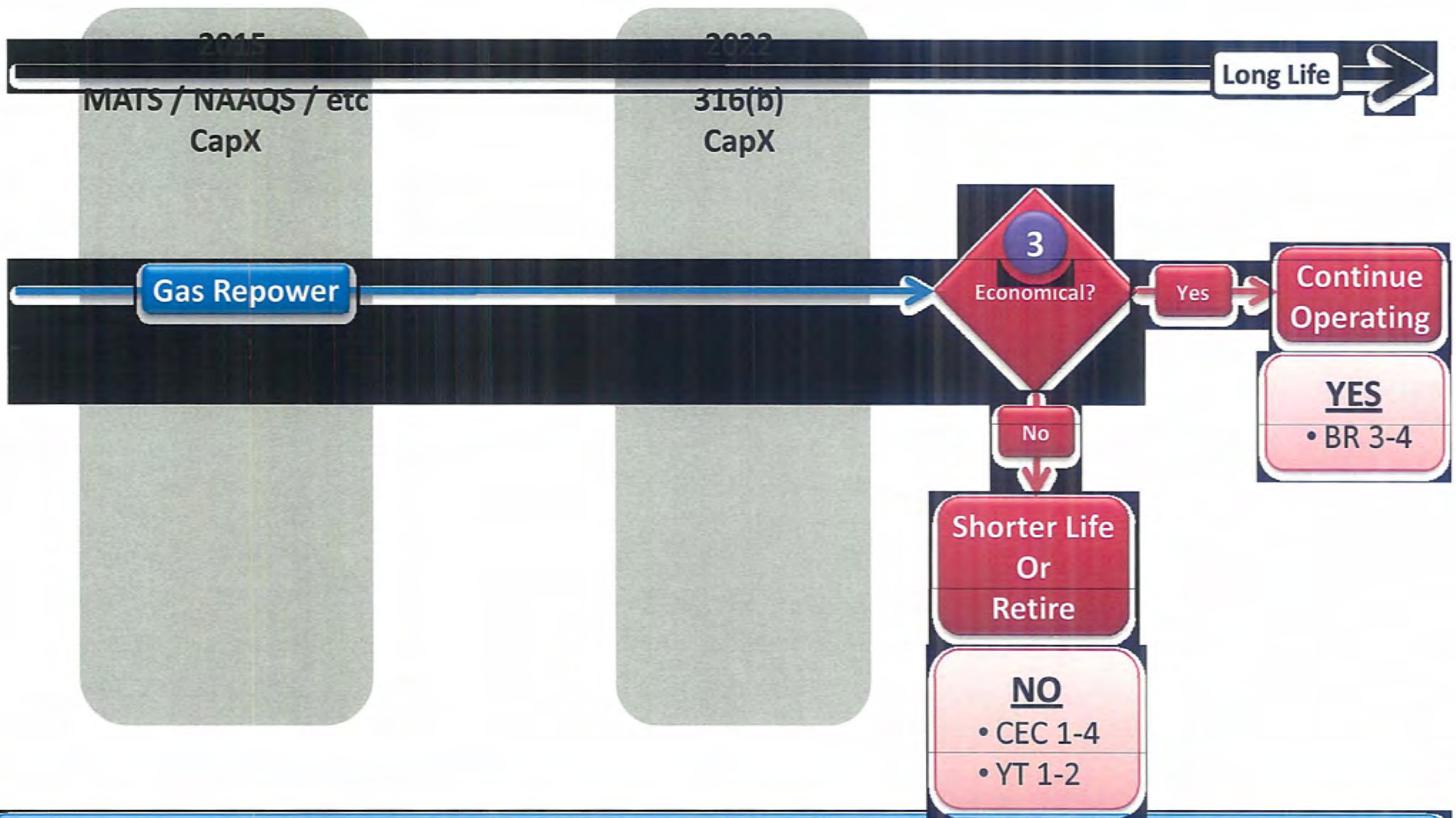
Coal-fired generator



10-year life, included all CapX except 316(b) - cooling tower expense

Decision Analysis (continued)

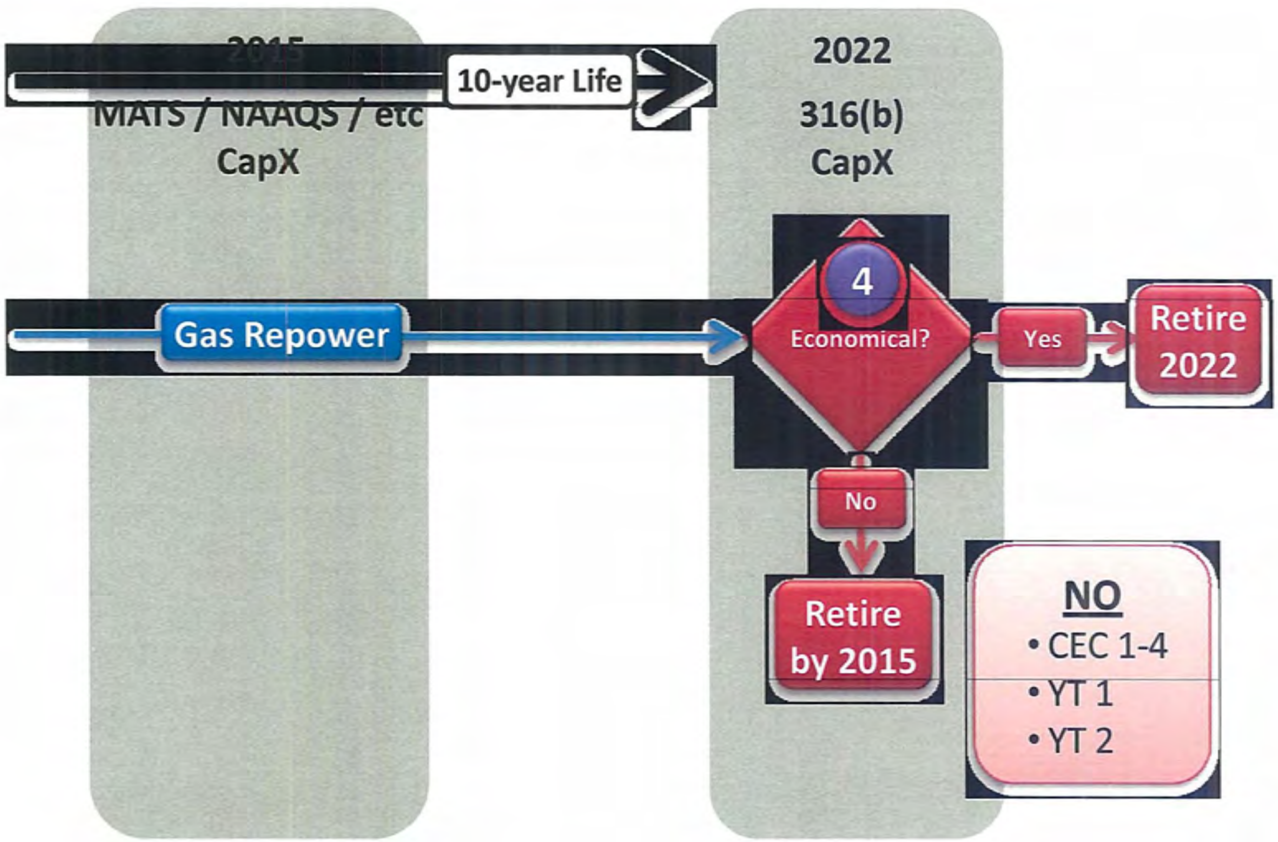
Coal-fired generator



Long life, repowered to Natural Gas, included all CapX on Gas

Decision Analysis (continued)

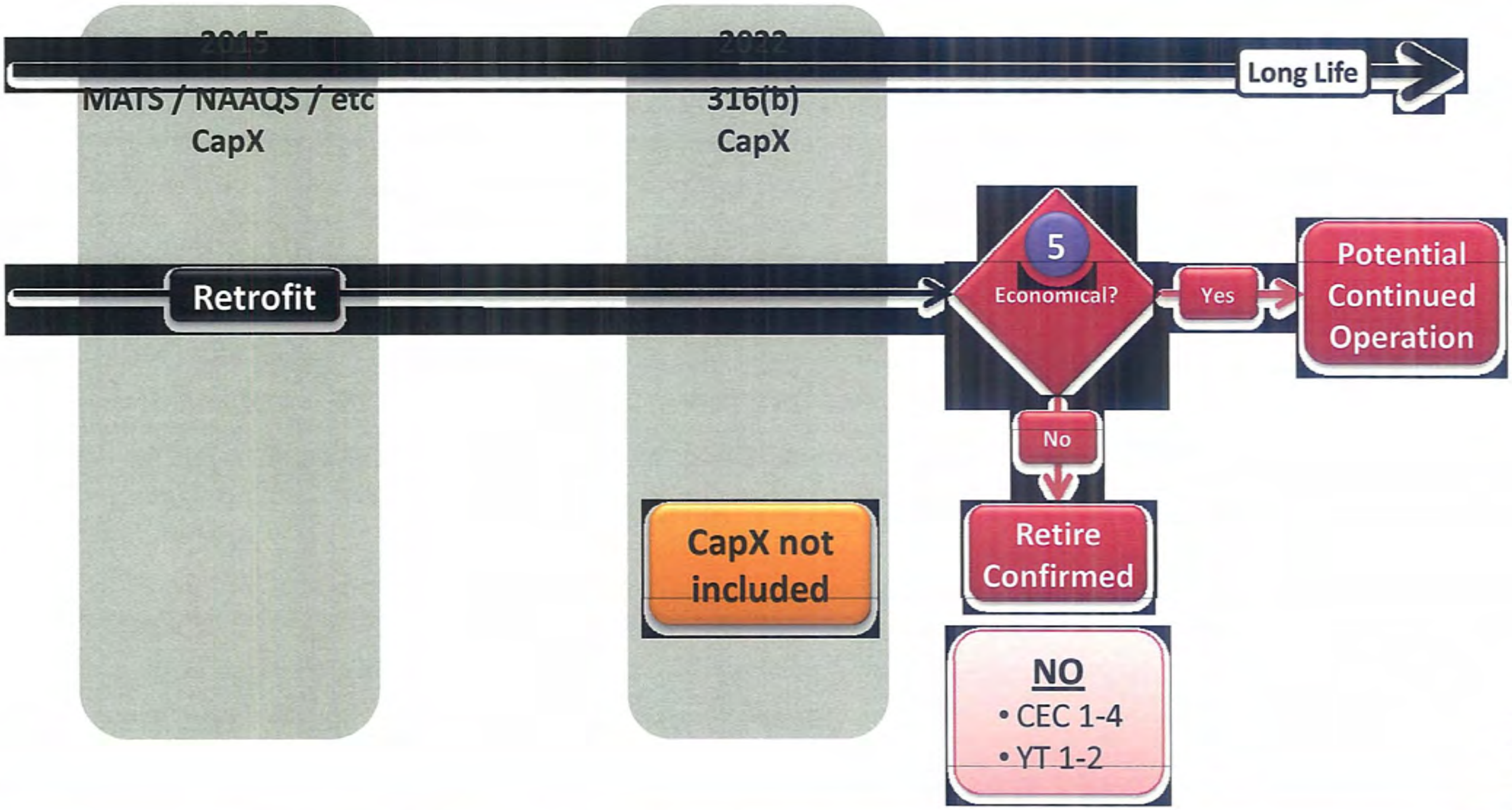
Coal-fired generator



10-year life, included all Gas CapX except 316(b) expense

Decision Analysis – final check

Coal-fired generator



If retired, check long life – included all CapX except 316(b) expenses

Summary

Best for Customers

- ❑ Retrofit heavy oil units (PP5 & YT3)
  - Low CapX
  - Preserve capacity
  - Support fuel diversity
- ❑ Retrofit small coal units (CH3, ME1&2)
  - Low CapX
  - Support fuel diversity
- ❑ Repower Bremo (BR3 & BR4)
  - Low CapX
  - Nearby gas pipeline
- ❑ Retire small coal units (CEC1-4, YT1&2)
  - High CapX
  - Lack of gas pipeline
  - MATS drives retirement date

2012 IRP

Year	New	Retrofit	Repower	Retire
2013	solar community		**AV – bimoass** **HW – biomass** **SH – biomass**	
2014	municipal solid waste		**BR3 – gas** **BR4 – gas**	
2015	CC (Warren)	**PP5 – SNCR**		**CEC 1-4** **YT 1&2**
2016	CC (Brunswick)			
2017				
2018		**YT3 – SNCR**		
2019	CC1			
2020	solar tag			
2021	CT1			
2022	CT2 Wind1			
2023	Wind2			
2024	North Anna 3 Wind3			
2025				
2026				
2027				

Nomenclature

Environmantal Regulations

- CAIR – Clean Air Interstate Rule
- CATR – Clean Air Transport Rule
- CCB – Coal Combustion Byproduct
- CO_2 – Carbon Dioxide
- CSAPR – Cross State Air Pollution Rule
- DC – District of Columbia
- EPA – Environmental Protection Agency
- GHG – Greenhouse Gas
- MATS – Mercury & Air Toxics Standards
- MW – megawatt
- NAAQS – National Ambient Air Quality Standard
- NO_x – Nitrogen Oxide
- NSPS – New Source Performance Standards
- PM – Particulate Matter
- ppb – parts per billion
- PSD – Prevention of Significant Deterioration
- SO_2 – Sulfur Dioxide

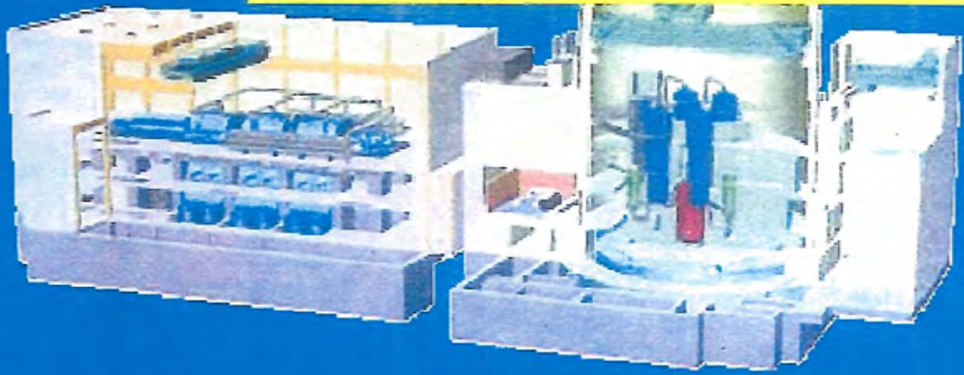
Generation / Controls

- BH – Baghouse
- CaBR2 – Calcium Bromide
- CapX – Capital Expenses
- CC – Combined Cycle
- CT – Combustion Turbine
- DFGD – Dry Flue Gas Desulfurization
- DSI – Dry Sorbent Injection
- ESP – Electrostatic Precipitator
- FD – Forced Draft
- FGD – Flue Gas Desulfurization
- FT – Firm Transportation
- ID – Induced Draft
- ROFA – Rotating OverFire Air
- SNCR – Selective Non-Catalytic Reduction
- SCR – Selective Catalytic Reduction
- VSD – Variable Speed Drive

Generation Facilities

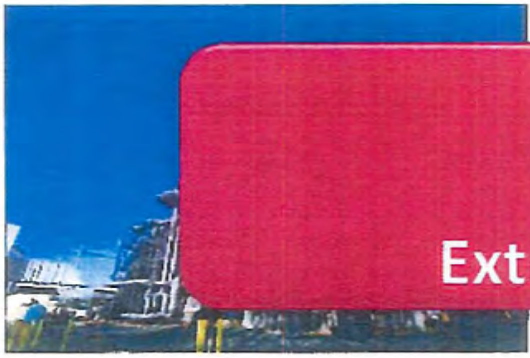
- BR – Bremo
- BW – Brunswick
- CEC – Chesapeake
- CH – Chesterfield
- ME – Mecklenburg
- MS – Mount Storm
- PP – Possum Point
- YT – Yorktown

SUPPLEMENTAL



IRP - Generation Process including an Environmental Regulation Discussion

Sep 6, 2012



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Existing Resources

Retrofits (Environmental Impacts)

Large CapX

- Scrubber
- Baghouse
- SCR
- Cooling Tower

	Incremental Retrofit Assumptions															
	SO_2/MATS/PM				NO_x		Hg		316 (b)		Eff	CCB				
Unit	Dry Scrubber Installation	Wet Scrubber Installation	DSI (Sodium Bicarbonate)	Baghouse	SCR	SNCR	ACI	Calcium Bromide	Intake Screens / VSD	Closed Cycle Cooling	Water Treatment Upgrades	CCB Convert To Dry Ash	316b Closed Cycle Cooling (2018-2022)	Other CapEx (2012-2022)	TOTAL CapEx (2012-2022)	Comment
BR - Bremo 3 & 4									X		X					
CEC - Chesapeake 1 & 2	X			X	X				X	X	X	X				316 (b) is 36% of total CapEx
CEC - Chesapeake 3 & 4	X			X					X	X	X	X				316 (b) is 51% of total CapEx
CH - Chesterfield 3,4, 5 & 6									X		X	X				
CL - Clover 1 & 2											X					
ME - Mecklenburg 1 & 2											X					
MS - Mount Storm 1, 2, & 3											X					
PP - Possum Point 3, 4 & 6									X		X					
PP - Possum Point 5						X					X					
YT - Yorktown 1 & 2	X			X	X				X	X	X					316 (b) is 40% of total CapEx
YT - Yorktown 3						X			X		X					
													$761 M	$1,697 M	$2,458 M	

* Blue Sheet Data 6-25-2012

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Gas and Electric
Infrastructure

Gas Transmission
20-year contract

2012 IRP	
Location	Levelized cost (annual)
2 CT, generic	
CC, generic	
Chesapeake	
Yorktown	

Electric Transmission
50-year life

2012 IRP	
Location	Levelized cost (annual)
Bremo	
Chesapeake	
Yorktown	

Electric Transmission is considerably less expensive than Gas Transmission

PUBLIC VERSION
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Comparison Summary

Retrofit vs. New

Yellow shaded area – Confidential data
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	Retrofit	CC (3x1)
Capacity	915 MW	1,375 MW
CapEx		
Book Life	30-yrs	36-yrs
Avg Capacity Factor	29%	68%
NPV against MKT		

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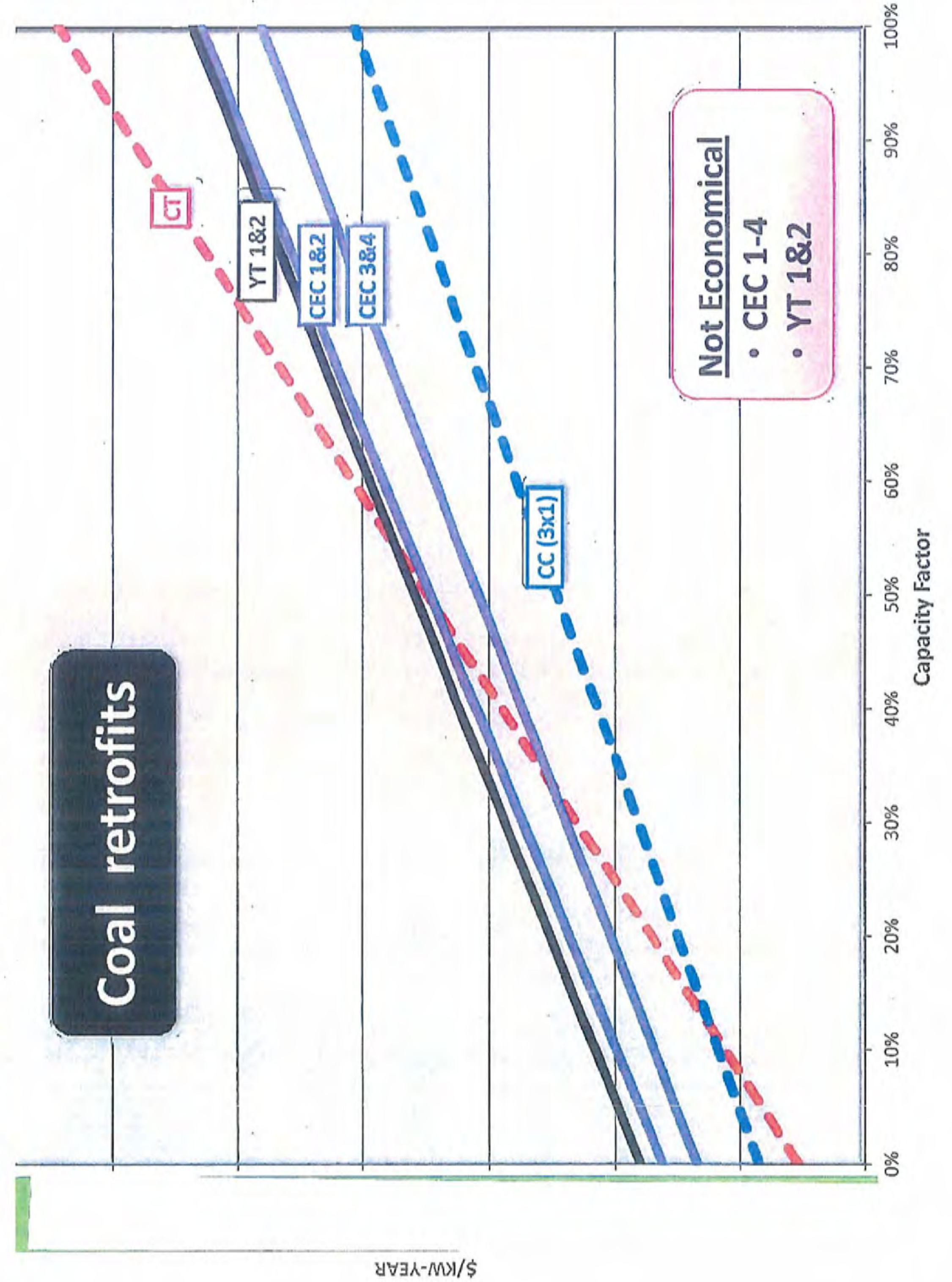
Screening Curve

Existing Resources (Coal Retrofit)



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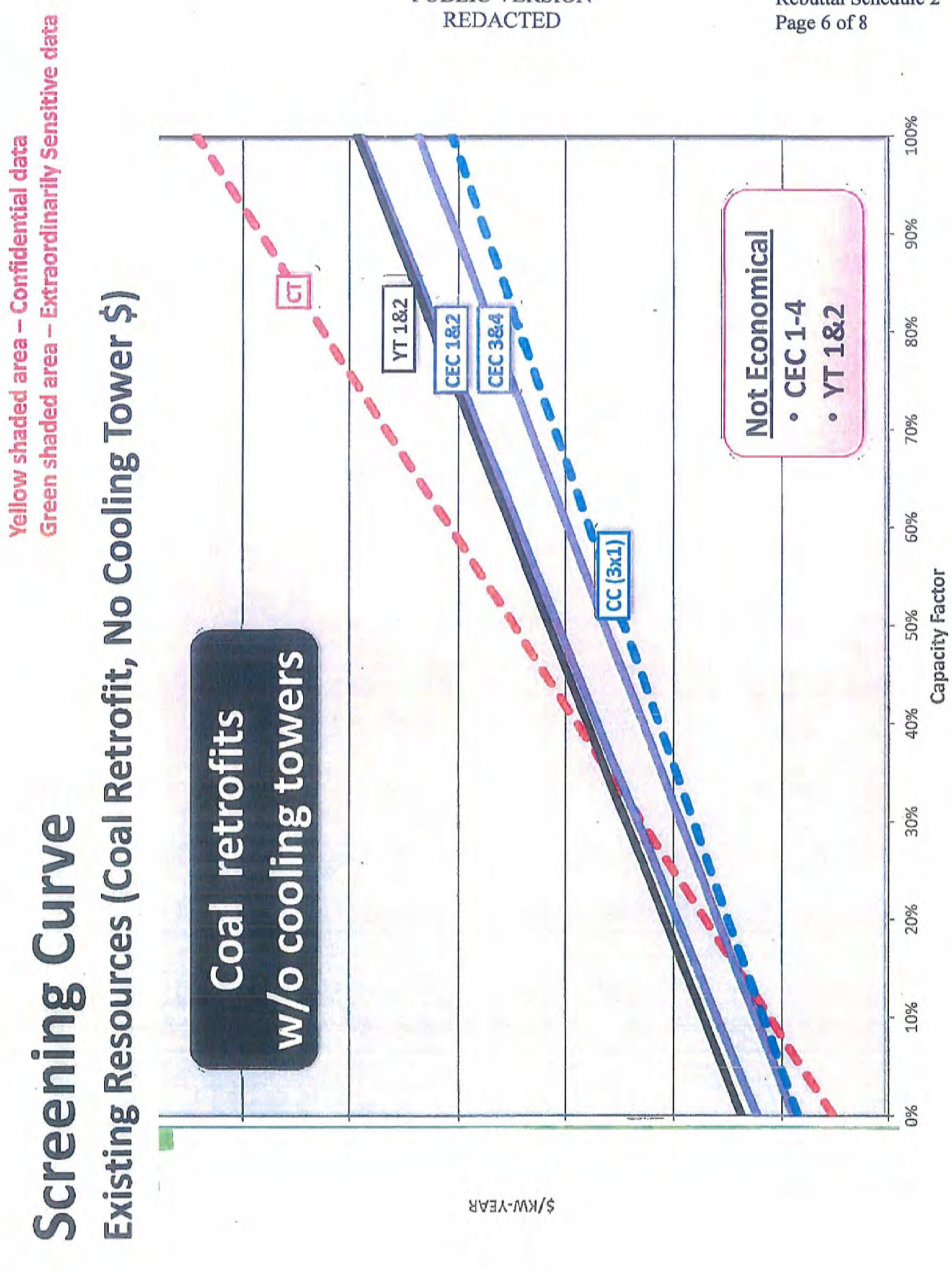
Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 2
Page 6 of 8



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Screening Curve

Existing Resources (Gas Repower)

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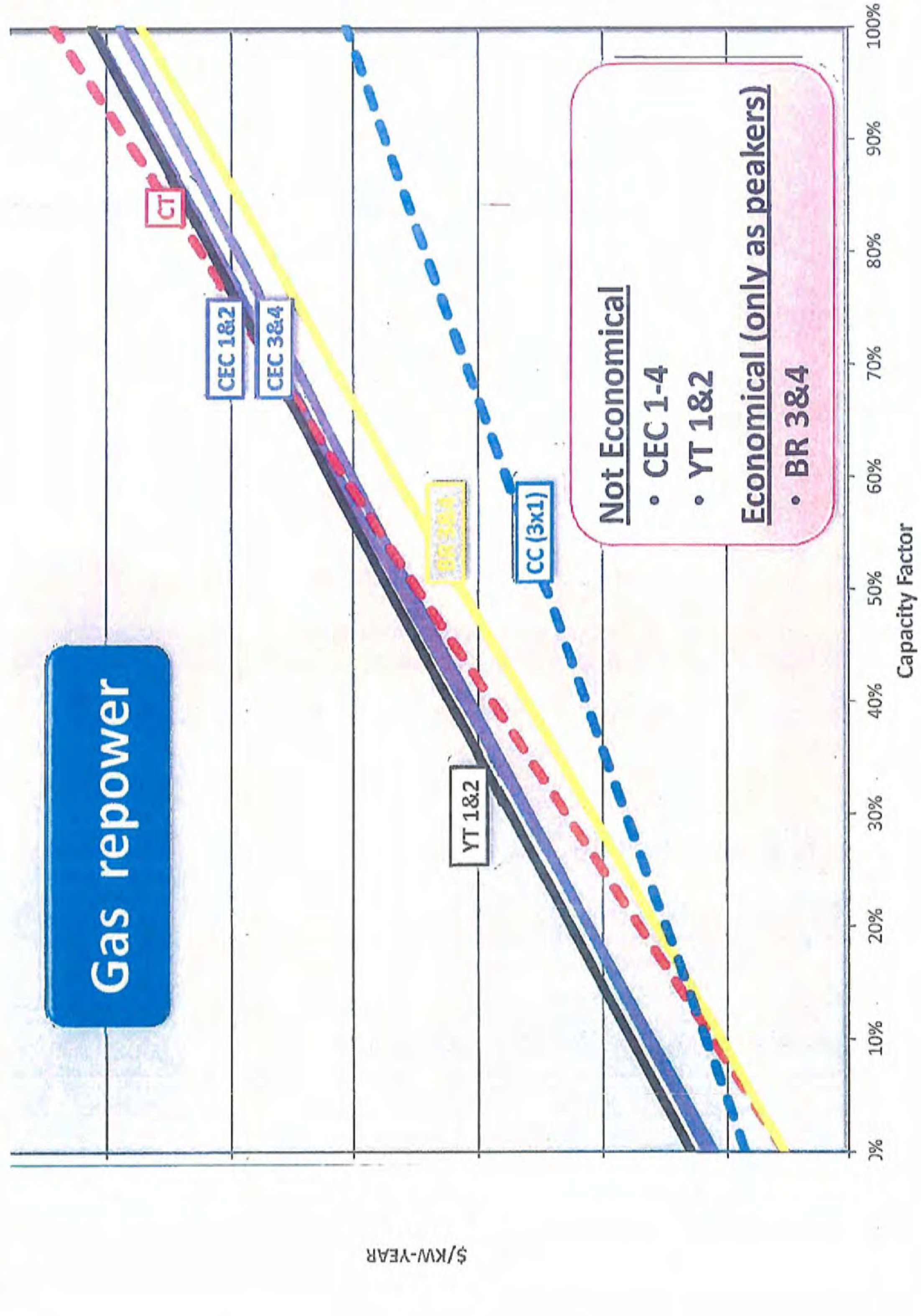

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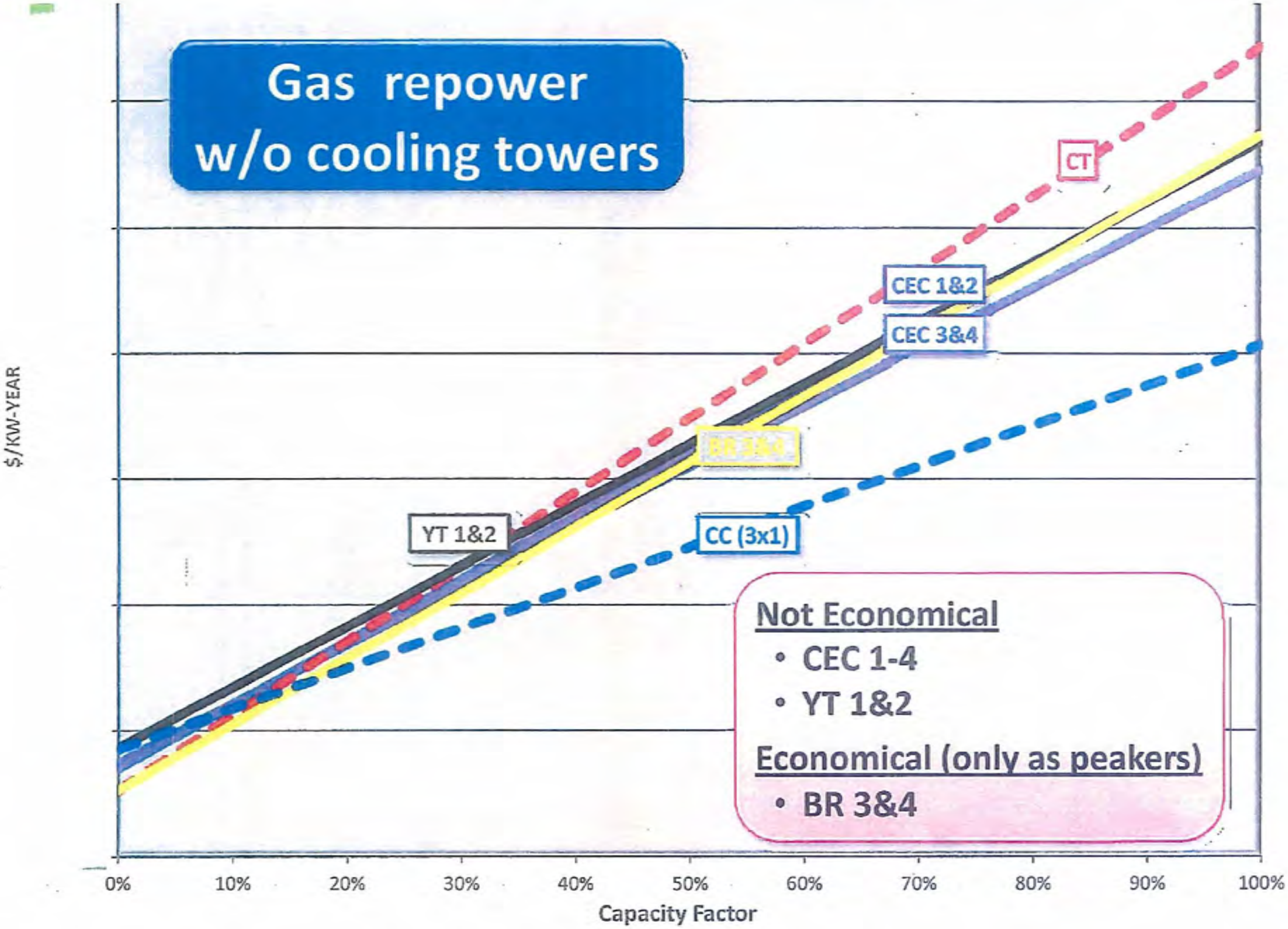
Screening Curve

Existing Resources (Gas Repower, No Cooling Tower $)



Generation Analysis Required by January 30 Ruling Assumptions and Nomenclature

All Information on this Page Public

- Text shaded in red are public, all other values are extraordinarily sensitive
- Text shaded in light gray are generation options not available in that year
- All expenditures are incremental from the 2012 IRP
- Incremental fuel expenses (excluding FT) have not been analyzed or included
- Retrofit and repower options require 3-years of capital expenditures for construction and implementation (excluding permitting), beginning July 1, 2013
- Only one generation option available at Yorktown that meet the MATS environmental compliance date by 2015:
    1. Yorktown Unit 3 can comply with MATS by limiting operations to 8% capacity factor per year
    2. This operating limit prevents YT3 from being considered as an available reliability resource
- Gas FT is not available at Yorktown until 2018
- Nomenclature:

CC – Combined cycle
CF – Capacity factor (limitation from MATS rule)
CT – Combustion turbine
FT – Firm transportation service
IT – Interruptible transportation service
IRP – Integrated resource plan
M – Million
MATS – Mercury & Air Toxics Standards
MW – Megawatts
YT – Yorktown

Yorktown Generation Options (Alternative A)
1,008 MW in 2015

All Information on this Page
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$350 M, 975 MW Available all hours

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Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 3
Page 3 of 11

Yorktown Generation Options (Alternative A)
1,449 MW (2 units min, 1 unit ≥ 87 MW) in 2021

All Information on this Page
Extraordinarily Sensitive
(except red text, which is public)

$350 M, prior 2015 expenditures

$927 M, 1,494 MW Available all hours
Total Alternative A [2015 + 2021]

Yorktown Generation Options (Alternative B)
159 MW in 2015

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Yorktown Generation Options (Alternative B)
551 MW (2 units min, 1 unit ≥ 27 MW) in 2021

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$677 M, 1,494 MW Available all hours
Total Alternative B [2015 + 2021]

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Yorktown Generation Options (Alternative C)
552 MW (2 units min, 1 unit ≥ 56 MW) in 2015

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$350 M, 975 MW Available all hours

Yorktown Generation Options (Alternative C)
505 MW (2 units min, 1 unit ≥ 139 MW) in 2021

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$350 M, prior 2015 expenditures

$927 M, 1,494 MW Available all hours
Total Alternative C [2015 + 2021]

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Yorktown Generation Options (Stand-Alone)
620 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2015

$633 M, 1,134 MW Available all hours

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Company Exhibit No. __
Witness: GAK
Rebuttal Schedule 3

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Yorktown Generation Options (Stand Alone)
620 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2021

$ 633 M, prior 2015 expenditures

$1,345 M, 1,653 MW Available all hours
Total Stand Alone [2015 + 2021]

Retaining Yorktown Generation
Retain YT1 and YT2 in 2015

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$383 M, 316 MW Available all hours

PUBLIC VERSION
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Retaining Yorktown Generation
Retain YT1 and YT2 thru 2023

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$ 383 M, prior 2015 expenditures

$ 652 M, 316 MW Available all hours
TOTAL thru 2023

Swanson

REBUTTAL TESTIMONY
OF
KURT W. SWANSON
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address, and position of employment with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. My name is Kurt W. Swanson. I am Project Director – Regulation for the Company. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. Have you previously provided testimony in this proceeding?

A. No, I have not.

Q. What is your educational and professional background?

A. I graduated from the University of Virginia in 1975 with a Bachelor of Arts degree in Economics and received a Master's of Business Administration degree from the University of Richmond in 1994. I was hired by Virginia Electric and Power Company in 1976. From 1976 to 1980, I worked in Commercial Operations in the Customer Service Department. In 1980, I was promoted to the position of Rate Analyst in the Company's Rate Department, and in 1983, I was promoted to Supervisor of Engineering Analysis, responsible for the preparation of the Company's load research studies. In December 1985, I was appointed Regulatory Specialist in the Rate and Load Research section of the Rate Department. Effective June 1, 2002, I was appointed to Manager – Regulatory and Pricing. On December 1, 2011, I was appointed Director – Regulation, and on January 1, 2013, I was appointed Project Director – Regulation. My current responsibilities include preparation of special projects in the Company's cost allocation and pricing department. I previously presented testimony before the Virginia State Corporation Commission, the North Carolina Utilities Commission, and the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to a request by the Hearing Examiner during the January 10, 2013 public hearing for the Company to provide estimated customer rate impacts of the Company's proposed Skiffes Creek transmission project and certain alternatives to the Project as follows:

- (i) Overhead Surry-Skiffes Creek 500 kV Transmission Line, (ii) Overhead Skiffes Creek-Whealton 230 kV Transmission Line, and (iii) Skiffes Creek 500 kV-230 kV-115 kV Switching Station ("Proposed Project with the 500 kV Updated Proposed Route");
- (i) Overhead Chickahominy-Skiffes Creek 500 kV Transmission Line, (ii) Overhead Skiffes Creek-Whealton 230 kV Transmission Line, and (iii) Skiffes Creek 500 kV-230 kV-115 kV Switching Station ("Proposed Project with the 500 kV Chickahominy Alternative"); and
- (i) Underground Surry-Skiffes Hybrid 230 kV Double Circuit (1000 MVA/Circuit) Transmission Line, (ii) Overhead Skiffes Creek-Whealton 230 kV Transmission Line, and (iii) Skiffes Creek 230 kV-115 kV Switching Station ("Alternative B") including the costs for additional work needed for full compliance with NERC Reliability Standards in 2015.[1]

[1] I was provided the costs for my rate analysis by Company Witnesses Peter Nedwick and Mark S. Allen. Costs for the Updated Proposed Route and Alternate Route are set forth in Rebuttal Schedule 5 of Company Witness Nedwick's pre-filed rebuttal testimony. Costs for Alternative B and the additional work needed to achieve full compliance with NERC Reliability Standards in 2015 are set forth in Rebuttal Schedule 4 of Company Witness Allen's pre-filed rebuttal testimony.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. I am sponsoring Company Exhibit No. __, KWS, which consists of Rebuttal Schedules 1 and 2. Specifically, I am sponsoring Rebuttal Schedule 1, which presents revenue requirements by project and was prepared by the Company's Electric Transmission Regulation group, and Rebuttal Schedule 2, which was prepared under my supervision and direction. Both are accurate and complete to the best of my knowledge and belief.

Q. Please discuss your Rebuttal Schedules 1 and 2.

A. Rebuttal Schedule 1 provides the revenue requirements allocated to the Virginia jurisdiction by project (these amounts are shown in Column 9).

Rebuttal Schedule 2 takes the allocated Virginia jurisdiction revenue requirements by project from Rebuttal Schedule 1 and calculates estimated cents per kilowatt hour rates by project for the five major customer classes (Residential, GS-1, GS-2, GS-3 and GS-4), shown on Lines 7-9. Rate schedule rates (either dollars per kW or cents per kilowatt hour) are calculated, by project, and shown on Lines 15-17. These rate schedule rates are then used to calculate estimated typical bill impacts for generic customers served under Rate Schedules 1, GS-1, GS-2, GS-3, and GS-4, shown on Lines 21-23. The resulting percentage increases, by project, over typical bills that are based on rates in effect as of January 1, 2013, are shown on Lines 24-26.

Q. Mr. Swanson, please summarize the estimated residential customer bill impact for the Company's proposed Skiffes Creek transmission project and for each of the alternative projects you were asked to study.

A. For a residential customer using 1,000 kWh per month, the average weighted monthly residential bill (four summer months and eight base months) will change as follows:

The Company's Proposed Project with the 500 kV Updated Proposed Route would increase the residential customer's bill by $0.21 from $107.22 to $107.43, or by 0.20%. The Proposed Project with the 500 kV Chickahominy Alternative would increase the residential customer's bill by $0.22 from $107.22 to $107.44, or by 0.21%. Finally, Alternative B with the costs of additional facilities to achieve full compliance with NERC Reliability Standards would increase the residential customer's bill by $1.07 from $107.22 to $108.29, or by 1.00%.[2]

Q. Mr. Swanson, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.

[2] The total cost to fully resolve 2015 NERC Reliability Violations for Alternative A and Alternative B is the same as set forth in Rebuttal Schedule 5 of Company Witness Nedwick's pre-filed rebuttal testimony.

Company Exhibit No. __
Witness: KWS
Rebuttal Schedule 1
Page 1 of 1

Development of the Estimated Annual Revenue Requirements used to Estimate the Monthly Summer Bill Impacts [1]
($ Millions)

Description of Projects	(1) Beginning of of Year Amount [2]	(2) Depreciation [3] (1)/ 51	(3) End of Year Amount (1)-(2)	(4) Average Amount ((1)+(3))/2	(5) Net Plant Carrying Charge without Depreciation [4]	(6) Annual Revenue Requirement (2)+((4)*(5))	(7) Regional Cost Allocation % to Dominion Zone [5]	(8) Regional Cost Allocation to Dominion Zone (6)*(7)	(9) Allocation of Annual Revenue Requirement to Va Jurisdiction [6] 72.7784% of (8)
1 Proposed Project with the 500 kV Updated Proposed Route									
500 KV Line	61.1	1.2	59.9	60.5	14.0582%	9.7	12.3800%	1.2	0.9
230 kV Line	46.4	0.9	45.5	45.9	14.0582%	7.4	99.8400%	7.4	5.4
Total Transmission Line	107.5	2.1	105.4	106.4		17.1		8.6	6.2
500 KV Substation	7.4	0.1	7.3	7.3	14.0582%	1.2	12.3800%	0.1	0.1
230 kV Substation	40.5	0.8	39.7	40.1	14.0582%	6.4	99.8400%	6.4	4.7
Total Substation	47.9	0.9	47.0	47.4		7.6		6.6	4.8
Total Project (Total Transmission Line and Substation)	155.4	3.0	152.4	153.9		24.7		15.1	11.0
2 Proposed Project - 500 kV Chickahominy Alternate Route									
500 KV Line	115.5	2.3	113.2	114.4	14.0582%	18.3	12.3800%	2.3	1.7
230 kV Line	46.4	0.9	45.5	45.9	14.0582%	7.4	99.8400%	7.4	5.4
Total Transmission Line	161.9	3.2	158.7	160.3		25.7		9.6	7.0
500 KV Substation	10.7	0.2	10.5	10.6	14.0582%	1.7	12.3800%	0.2	0.2
230 kV Substation	40.6	0.8	39.8	40.2	14.0582%	6.4	99.8400%	6.4	4.7
Total Substation	51.3	1.0	50.3	50.8		8.1		6.6	4.8
Total Project (Total Transmission Line and Substation)	213.2	4.2	209.0	211.1		33.9		16.3	11.8
3 Alternative B									
500 KV Line	0	0.0	0.0	0.0	14.0582%	0.0	12.3800%	0.0	0.0
230 kV Line	390.2	7.7	382.5	386.4	14.0582%	62.0	99.8400%	61.9	45.0
Total Transmission Line	390.2	7.7	382.5	386.4		62.0		61.9	45.0
500 KV Substation	0.0	0.0	0.0	0.0	14.0582%	0.0	12.3800%	0.0	0.0
230 kV Substation	50.2	1.0	49.2	49.7	14.0582%	8.0	99.8400%	8.0	5.8
Total Substation	50.2	1.0	49.2	49.7		8.0		8.0	5.8
Total Project For Partial Compliance (Total Transmission Line and Substation)	440.4	8.6	431.8	436.1		69.9		69.8	50.8
Additional Work Needed for Full Compliance	48.2	0.9	47.3	47.7	14.0582%	7.7	99.8400%	7.6	5.6
Total Project For Full Compliance (Total Transmission Line and Substation)	488.6	9.6	479.0	483.8		77.6		77.5	56.4

Notes:

[1] The methodology for developing the estimated annual revenue requirements is based on the methodology included in Attachment 7 of Dominion's formula rate approved by FERC. The populated version of Dominion's 2012 Formula rate can be obtained from the PJM website (see the link below).
http://pjm.com/markets-and-operations/transmission-service/~/media/markets-ops/trans-service/20120112-virginia-electric-and-power-company-2012-formula-rate-informational-filing.ashx

[2] The Beginning of Year Amount is an estimate of the applicable project's costs.

[3] 51 years is the assumed amortization period of each project and it corresponds to the life used to determine depreciation in Attachment 7 of Dominion's formula rate.

[4] The Net Plant Carrying Charge without Depreciation is from Appendix A, (line 154) of the populated version of Dominion's 2012 formula rate - see note 1. It is based on the following cost of capital from that same Appendix A (see lines 112 - 129).

	Capitalization Ratios	Costs	Weighted Costs
Debt Cost	44.9%	5.61%	2.52%
Preferred Cost	1.8%	6.43%	0.11%
Common Cost	53.3%	11.40%	6.08%
Total Return			8.71%

[5] These allocations percentages are from Schedule 12 Appendix of the PJM Tariff, page 837.

[6] The 72.7784 % is the ratio of the Virginia jurisdictional peak demand coincident with the 2012 Network Service Peak Load of the Dominion Zone.

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Rebuttal Schedule 2
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VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL MONTHLY BILL IMPACT BY PROPOSED PROJECT ROUTE
DOCKET NO. PUE-2012-00029

LINE NO.		(1)	(2)	(3)	(4)	(5)	(6)
	1CP ALLOCATION [1]	VA JURISDICTION	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4
1	Class Demand at Time of 2011 System Peak	14,619,678	8,178,368	776,560	2,453,139	2,165,687	940,621
2	Class Allocation Factors		55.9408%	5.3117%	16.7797%	14.8135%	6.4339%
	REVENUE REQUIREMENT BY CLASS [2]	VA JURISDICTION	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4
3	Proposed Project - 500 kV Updated Proposed Route	$11,000,000	$6,153,490	$584,292	$1,845,768	$1,629,486	$707,733
4	Proposed Project - 500 kV Chickahominy Alternate Route	$11,800,000	$6,601,017	$626,786	$1,980,005	$1,747,994	$759,205
5	Alternative B	$56,400,000	$31,550,623	$2,995,824	$9,463,754	$8,354,818	$3,628,741
	CLASS KWH FORECAST [1]	KWH	KWH	KWH	KWH	KWH	KWH
6	12-Months Ending August 2013 kWh Sales	67,101,977,223	29,494,546,829	3,746,725,617	12,764,265,008	12,762,940,574	7,499,233,646
	CLASS RATE $/KWH	VA JURISDICTION	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4
7	Proposed Project - 500 kV Updated Proposed Route	$0.00016	$0.00021	$0.00016	$0.00014	$0.00013	$0.00009
8	Proposed Project - 500 kV Chickahominy Alternate Route	$0.00018	$0.00022	$0.00017	$0.00016	$0.00014	$0.00010
9	Alternative B	$0.00084	$0.00107	$0.00080	$0.00074	$0.00065	$0.00048
			RESIDENTIAL	SGS	SGS-INT	LGS-SECONDARY	LGS-PRI
	RATE SCHEDULE FORECAST [1]		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
10	12 Mos Ending August 2013 kWh Sales		29,229,792,766	3,735,985,444	9,859,498,356	10,541,462,945	6,615,432,173
	REVENUE REQUIREMENT BY RATE SCHEDULE		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
11	Proposed Project - 500 kV Updated Proposed Route		$6,098,254	$582,617	$1,425,726	$1,345,863	$624,325
12	Proposed Project - 500 kV Chickahominy Alternate Route		$6,541,764	$624,989	$1,529,415	$1,443,743	$669,731
13	Alternative B		$31,267,413	$2,987,236	$7,310,086	$6,900,604	$3,201,086
			KWH	KWH	KW	KW	KW
14	RATE SCHEDULE KWH OR KW FORECAST [1]		29,229,792,766	3,735,985,444	27,671,780	21,912,195	11,723,337
	RATE SCHEDULE $/KWH OR $/KW AS APPLICABLE		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
15	Proposed Project - 500 kV Updated Proposed Route		$0.00021	$0.00016	$0.052	$0.061	$0.053
16	Proposed Project - 500 kV Chickahominy Alternate Route		$0.00022	$0.00017	$0.055	$0.066	$0.057
17	Alternative B		$0.00107	$0.00080	$0.264	$0.315	$0.273
	BILLING DETERMINANTS BY RATE SCHEDULE FOR A TYPICAL CUSTOMER		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
18	kW		N/A	15 kW	40 kW	1,000 kW	10,000 kW
19	kWh		1,000 kWh	6,000 kWh	15,000 kWh	500,000 kWh	6,000,000 kWh
			SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
20	JANUARY 1, 2013 BILL AMOUNT		$107.22	$519.55	$1,218.26	$32,828.25	$341,639.15
	BILL CHANGE BY RATE SCHEDULE		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
21	Proposed Project - 500 kV Updated Proposed Route		$0.21	$0.96	$2.08	$61.00	$530.00
22	Proposed Project - 500 kV Chickahominy Alternate Route		$0.22	$1.02	$2.20	$66.00	$570.00
23	Alternative B		$1.07	$4.80	$10.56	$315.00	$2,730.00
	PERCENTAGE CHANGE BY RATE SCHEDULE		SCHEDULE 1	SCHEDULE GS-1	SCHEDULE GS-2	SCHEDULE GS-3	SCHEDULE GS-4
24	Proposed Project - 500 kV Updated Proposed Route		0.20%	0.18%	0.17%	0.19%	0.16%
25	Proposed Project - 500 kV Chickahominy Alternate Route		0.21%	0.20%	0.18%	0.20%	0.17%
26	Alternative B		1.00%	0.92%	0.87%	0.96%	0.80%

[1] *From the Company's Transmission Rider T1 case Docket No. PUE-2012-00052.*
[2] *See Company Witness KWS Rebuttal Schedule 1 Column 9 for the Va Jurisdiction revenue requirements.*