

Division 2-15

Request:

Please describe in detail the distribution capital investment planning and approval (internal and regulatory) process for each US jurisdiction. This should include but not be limited to the planning horizon, the components/spending categories of the plan, how projects are prioritized for inclusion in the plan, required studies to supplement the plans, internal/regulatory approval steps, regulatory filing requirements, how project implementation is tracked, and applicable spending caps, penalties, or company performance incentives.

Response:

On June 15, 2021, counsel for PPL and PPL RI, as well as counsel for National Grid USA and The Narragansett Electric Company met and conferred with counsel for the Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") seeking clarification on the nature and the scope of this request. On June 22, 2021, the Division Advocacy Section sent a letter providing clarification regarding this request. Specifically, the Division Advocacy Section clarified that this request is directed to PPL and seeks the requested information regarding the jurisdictions in which PPL currently operates. Accordingly, PPL and PPL RI respond below consistent with this clarification.

**Pennsylvania**

The distribution capital investment plan for PPL Electric Utilities Corporation ("PPL Electric") in Pennsylvania is tracked in three categories, Distribution System Improvement Charges ("DSIC"), Provider Electrical Service ("PES") and Operations. DSIC is associated with the Long-Term Infrastructure Improvement Plan ("LTIIP"), a voluntary 5-year plan subject to approval and audit by the Pennsylvania Public Utility Commission ("PaPUC"), designed to accelerate the replacement of aging infrastructure and increase reliability of the overall electrical system. PES is work in support of customer requests, including such activities as attaching new residential service, or line extensions in support of new commercial construction. Operations includes all work that maintains the current state of the electrical system, mainly through the planned replacement of equipment as well as responding to real-time failures due to age or weather.

Prior to investment planning each year, PPL Electric sets the investment strategy that aligns with key business objectives and goals. The investment strategy is generally broken out into buckets or categories such as, but not limited to, asset optimization, compliance or regulatory requirements, system reliability improvements, strategic initiatives, and customer driven work. As part of the annual investment planning process, several analyses and studies are utilized to prioritize projects

or programs, where each analysis or study is weighed against the portfolio priorities, business needs, benefits, and risks to ultimately be considered for investment. Notably, as changes to this investment plan are proposed or warranted, all changes are processed through a governance committee for final approval or rejection. Furthermore, several key performance indicators are used to track project status throughout the year, measuring work completion, impediments, project spend, and forecasts.

An annual business planning summit allows for senior leadership to review the business plan and consider any significant changes that the business lines are requesting to meet their goals. In addition to the annual summit, any required changes to the plan are also reviewed through a monthly governance process. This ensures the proposed changes are warranted and align to overall strategy. Company performance incentives are associated with overall performance goals in the following categories: reliability, customer satisfaction and financial performance.

PPL Electric has two regulatory processes for capital investment approval. First, PPL Electric files distribution base rate cases on an as needed basis. As part of this process, PPL Electric submits extensive financial data for a future test year and a fully projected future test year as well as testimony describing the revenue request. Interrogatory requests are submitted by intervenors to further determine reasonableness. Second, Pennsylvania allows for utilities such as PPL Electric to file for a Long-Term Infrastructure Improvement Plan ("LTIIP") and associated Distribution System Improvement Charge ("DSIC"). Certain modifications to a company's LTIIP must also be filed with and approved by the PA PUC. The LTIIP: (a) establishes a 5-year plan to repair, improve, or replace eligible property, which projects are completed, placed in service, and recorded in certain FERC accounts between base rate cases, and (b) provides utilities with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems. The DSIC is a cost recovery mechanism specifically design to recover costs in the LTIIP. See Attachment PPL-DIV 2-15-1 – PPL Electric Distribution System Improvement Charge Tariff.

### **Kentucky**

Louisville Gas & Electric Corporation ("LG&E") and Kentucky Utilities Corporation ("KU") (collectively "LKE") Electric Distribution Operations ("EDO") capital and investment planning and approval processes adhere to the LG&E and KU Energy LLC Capital and Investment Review Policy, a copy of which is provided as Attachment PPL-DIV 2-15-2. In support of this process, LKE EDO leverages an Asset Investment Strategy ("AIS") decision-support model to help evaluate and prioritize distribution investment programs, projects, and budgets to be considered for inclusion in annual, mid-term, and long-term business plans. The AIS model and associated business processes enable evaluation and prioritization of proposed investments based on (a) a set of custom benefit criteria defined by subject matter experts; and (b) estimated costs of proposed

projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn enables LKE EDO to determine the best allocation of capital funding. LKE EDO applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to be included in its capital business plans.

For additional information regarding capital investment planning and approval processes of LKE EDO, PPL and PPL RI also refer to Attachment PPL-DIV 2-15-3 – Authority Limit Matrix, as well as Attachment PPL-DIV 2-15-4 – Resource Allocation Committee Charter.

LKE EDO reviews all proposed capital projects to determine whether a Certificate of Public Convenience and Necessity (“CPCN”) or any other regulatory approval is required. KRS 278.020(1) requires a utility receive a CPCN from the Kentucky Public Service Commission (“KPSC”) prior to construction of any plant, equipment, property, or facility unless the construction is an “[o]rdinary extension of existing systems in the usual course of business.” 807 KAR 5:001, Section 15(3) provides that extensions are in the ordinary course of business when they do not result in the wasteful duplication of utility plant, do not compete with the facilities of existing public utilities, and do not involve a sufficient capital outlay to materially affect the existing financial condition of the utility involved or to require an increase in utility rates. In determining whether a project requires a CPCN or is an ordinary extension, LKE EDO considers these three factors. In addition, pursuant to KRS 278.020(2), construction of an electric transmission line of at least 138 kV and more than 5,280 feet in length shall require a CPCN, with certain limited exceptions.

LKE EDO reviews and considers the KPSC's guidance as to when a CPCN is necessary. The precedent continues to evolve, especially with regard to the relative magnitude of the capital outlay that may trigger the request for a CPCN. Particularly regarding materiality, the KPSC recently required that “any capital expenditure that exceeds \$100 million” will be considered material to LG&E and KU and require a CPCN.<sup>1</sup> Further, the KPSC has held that certain projects, such as smart grid deployments, and office buildings, as a matter of policy generally require a CPCN even if the project cost would not otherwise be considered material.

### **Virginia**

In Virginia, KU doing business as Old Dominion Power Company (“KU-ODP”) EDO follows the same capital and investment planning and approval process described above in Kentucky. Similarly, KU-ODP EDO reviews all proposed capital projects to determine whether a CPCN or

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<sup>1</sup> *Electronic Application of Kentucky Utilities Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Order (Ky. PSC Sept. 29, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2020-00061, Order (Ky. PSC Sept. 29, 2020).

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY  
Docket No. D-21-09  
PPL Corporation and PPL Rhode Island Holdings, LLC's  
Responses to Division's Second Set of Data Requests  
Issued on June 11, 2021

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any other regulatory approval is required. Virginia's CPCN laws, known as the "Utility Facilities Act," are found in Chapter 10.1 of Title 56 of the Code of Virginia. Specifically, Va. Code 56-265.2(A)(1) provides that a utility may not construct, enlarge, or acquire "any facilities for use in public utility service, except ordinary extensions or improvements in the usual course of business, without first having obtained a certificate from the Commission that the public convenience and necessity require the exercise of such right or privilege."

The Virginia State Corporation Commission ("VSCC") has explained that whether a particular facility is an ordinary extension or improvement in the usual course of business "necessarily requires a case-by-case determination."<sup>2</sup> Certain projects, such as a generating facility capable of producing 100 megawatts or more of capacity and certain transmission lines 138 kV or greater, require a CPCN regardless of whether the project may be considered an ordinary extension. In situations where it is unclear whether a CPCN is necessary, the VSCC's Rules of Practice and Procedure permit the initiation of both formal and informal actions to provide clarity. Thus, when it is unclear whether a project constitutes an ordinary extension or improvement for which a CPCN is not necessary, KU-ODP seeks guidance from the VSCC.

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<sup>2</sup> *Petition of William C. Barnhardt*, Case No. PUE-2015-00109, Order at 8-9 (Va. SCC Dec. 11, 2015).

## PPL Electric Utilities Corporation

Supplement No. 300  
Electric Pa. P.U.C. No. 201  
Thirty-Second Revised Page No. 19Z.16  
Canceling Thirty-First Revised Page No. 19Z.16

### DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply **(C)** consistent with the Commission Order dated May 23, 2013, at Docket No. P-2012-2325034, approving the DSIC. This charge will be effective during the period October 1, 2020 through December 31, 2020.

#### GENERAL DESCRIPTION

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide PPL Electric with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

- Poles and towers (Account 364);
- Overhead conductors (Account 365) and underground conduit and conductors (Accounts 366 and 367);
- Line transformers (account 368) and substation equipment (Account 362);
- Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, converters and condensers;
- Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
- Other related capitalized costs.

C. Effective Date: The DSIC will become effective for bills rendered on and after July 1, 2013.

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# PPL Electric Utilities Corporation

Supplement No. 214  
 Electric Pa. P.U.C. No. 201  
 Fourth Revised Page No. 19Z.17  
 Canceling Third Revised Page No. 19Z.17

## DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (Continued)

### COMPUTATION OF THE DSIC

A. Calculation: The initial DSIC, effective July 1, 2013, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in PPL Electric's rates or rate base and will have been placed in service between March 1 through May 31, 2013. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Thus, changes in the DSIC rate will occur as follows:

(C)

<u>Effective Date of Change</u>	<u>Date to which DSIC-Eligible Plant Additions Reflected</u>
April 1st	December 1st – February 28th
July 1st	March 1st – May 31st
October 1st	June 1st – August 31st
January 1st	September 1st – November 30th

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in PPL Electric's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, PPL Electric's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in PPL Electric's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service under PPL Electric's otherwise applicable rates and charges, excluding amounts billed for the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by PPL Electric's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

(Continued)

(I) Indicates Increase (D) Indicates Decrease (C) Indicates Change

Issued: October 31, 2016

Effective: November 1, 2016

## PPL Electric Utilities Corporation

Supplement No. 214  
Electric Pa. P.U.C. No. 201  
Second Revised Page No. 19Z.18  
Canceling First Page No. 19Z.18

### DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (Continued)

#### COMPUTATION OF THE DSIC (Continued)

D. Formula: The formula for calculation of the DSIC is as follows:

$$\text{DSIC} = \frac{((\text{DSI} \times \text{PTRR}) + \text{Dep} + e)}{\text{PQR}} \times \frac{1}{(1-T)}$$

Where:

- DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation.
- PTRR = Pre-tax return rate applicable to DSIC-eligible property.
- Dep = Depreciation expense related to DSIC-eligible property.
- e = Amount calculated (+/-) under the annual reconciliation feature or **(C)** Commission audit, as described below.
- PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be gained or lost by the beginning of the applicable service period.
- T = Pennsylvania gross receipts tax rate in effect during the billing month, expressed in decimal form.

Minimum bills shall not be reduced by reason of the DSIC, nor shall charges hereunder be a part of the monthly rate schedule minimum. The DSIC shall not be subject to any credits or discounts. The State Tax Adjustment Surcharge (STAS) included in this Tariff is applied to charges under the DSIC.

#### QUARTERLY UPDATES

Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

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## PPL Electric Utilities Corporation

Supplement No. 214  
Electric Pa. P.U.C. No. 201  
Fourth Revised Page No. 19Z.19  
Canceling Third Revised Page No. 19Z.19

### DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (Continued)

#### CUSTOMER SAFEGUARDS

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq.*, shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or PPL Electric may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to PPL Electric's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year, or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq.*) and will be refunded in the same manner as an over-collection. PPL Electric is not permitted to accrue interest on under collections. (C)

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in PPL Electric's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert also shall be included with the first billing.

E. Customer classes: Effective July 1, 2013, the DSIC shall be applied equally to all customer classes except Rate Schedule LP-5, consistent with the Commission Order entered April 9, 2015 at Docket No. P-2012-2325034. Effective January 1, 2016, the DSIC shall be applied equally to all customer classes except Rate Schedules LP-5 and LPEP.

F. Earning Reports: The DSIC also will be reset at zero if, in any quarter, data filed with the Commission in PPL Electric's then most recent Annual or Quarterly Earnings reports (Schedule D-2) show that PPL Electric would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. PPL Electric shall file a tariff supplement implementing the reset to zero due to overearning on one-days' notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that PPL Electric has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs. (C)

## PPL Electric Utilities Corporation

Supplement No. 214  
Electric Pa. P.U.C. No. 201  
Original Page No. 19Z.19A

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### DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (Continued)

#### CUSTOMER SAFEGUARDS (Continued)

G. Residual E-Factor Recovery Upon Reset to Zero: PPL Electric shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. PPL Electric can recoup or refund the residual over/under collection balance when the DSIC rate is reset to zero. PPL Electric shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Customer Safeguard Section B. The tariff supplement shall be submitted in accordance with the Quarterly Updates section of this tariff. **(C)**

## **LG&E AND KU ENERGY LLC Policy**

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### **Capital and Investment Review**

#### **Policy**

The primary purpose of the Capital and Investment Review Policy is to establish a uniform process for:

1. capital planning and budgeting;
2. authorizing the expenditure of funds;
3. controlling and reporting of capital expenditures; and
4. developing review criteria for the authorization process.

Further, these policies will provide management with the necessary tools to make informed business decisions. A capital expenditure includes adding, replacing or retiring units of property through the construction or acquisition process. Generally, it is inappropriate to capitalize expenditures that are part of routine or necessary maintenance programs. If a substantial improvement is made to an asset, the following two sets of criteria should be used to determine whether or not capitalization is appropriate:

*The improvement must meet both of the following criteria:*

1. Be a minimum of \$5,000.
2. Meet the definition of a capitalizable cost under the [FERC Uniform System of Accounts](#).

*In addition, the improvement must do at least one of the following criteria:*

1. Extend the original useful life of the asset.
2. Increase the throughput or capacity of the asset.
3. Increase operating efficiency.

Questions relating to the categorization of an expenditure as capital or O&M expense should be directed to Property Accounting. The Controller will have the ultimate authority of interpreting expense versus capital decisions based on generally accepted accounting principles. See [Property Accounting's Home Page](#).

#### **Scope**

This policy applies to LG&E and KU Energy LLC (“LKE” or “the Company”) and its subsidiaries.

#### **General Requirements**

1. All capital spending that is expected to occur during the current year must be budgeted in the approved Business Plan (BP).
2. There will be no carry-over of spending capital authority from one year to the next.
3. An Authorization for Investment Proposal (AIP) must be completed in PowerPlan for all capital spending projects.

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

4. Projects with a total cost of \$5,000 or less will be expensed.
5. An [Investment Proposal](#) (IP) and [Capital Evaluation Model](#) (CEM) must be completed for all capital spending projects greater than \$1,000,000 unless otherwise approved by Director of Financial Planning & Budgeting (FP&B).
6. The Information Technology Department must approve all capital projects involving anything related to information technology.

### **Capital Planning**

The BP is used to inform senior management of future capital-spending projections. These plans are prepared annually on a line of business (LOB) basis and include the forecast of capital projections during the most current annual planning period. The first year of the BP, once approved, becomes the formal budget for that year.

*Carry-Over Spending:* During preparation of the BP, each LOB will review all current-year projects to determine if they will be completed as of the end of the year. If a project is expected to be in process at year-end, but not complete, it must be included in the following year's BP for additional funds to be approved.

### **Construction Overheads**

Per the Uniform System of Accounts, Electric Plant Instruction 4, costs related to construction activities but not directly related to a project, can still be capitalized in the form of a construction overhead or burden. This can be in the form of Local Engineering or the allocation of Administrative and General costs. See Appendix A for a detailed explanation of construction overheads and costs that can be included.

### **Capital Approval Process**

*Authorization for Investment Proposal:* Although specific capital projects are identified in the budgeting process, they are still subject to the [Authority Limit Matrix](#) approval requirements and all other reviews as stated on the AIP in PowerPlan. Projects are not considered approved until appropriate approvals are obtained.

The AIP is used to request the appropriate approvals for spending on capital projects. A completed AIP is subject to the following conditions:

- An AIP must be submitted and approved in PowerPlan prior to committing to or incurring any capital expenditure.
- Approvals must be obtained up to the levels designated in the [Authority Limit Matrix](#) for the dollar amount of any project (which may include multiple projects). The combined dollar amount on multiple projects grouped together using the Budget Item field in PowerPlan is the determinant for approval levels.
- Any AIP over \$1,000,000 must include an IP and CEM when submitted for approval.
- A completed AIP must be submitted and approved prior to the disposal of any capital asset. In addition, an IP must be submitted for disposal projects over \$1,000,000.
- A revised AIP must be submitted for significant project overruns (see below).

## **LG&E AND KU ENERGY LLC Policy**

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### **Capital and Investment Review**

*Investment Proposal:* The IP is used to explain in detail the nature and justification of the capital project. Capital projects over \$1,000,000 on a burdened basis require the submittal of an IP and CEM along with the AIP. The following information will provide senior management with consistent documentation for evaluating capital projects. The IP template is published on the Financial Planning & Analysis intranet or SharePoint Team website.

*Unbudgeted Projects:* Any capital expenditure that is not included in the original, approved budget must either be offset by a like reduction in one or more budgeted projects, approved by the Resource Allocation Committee (RAC) if subject to the RAC Charter or have prior written approval by the LKE Chief Financial Officer (CFO) and Chief Executive Officer (CEO). FP&B and/or Manager of Shared Services & Corporate Budget (SS&C) must approve AIPs for unbudgeted projects (see *FP&B and SS&C Approvals* below). Certain Generation Miscellaneous Projects, as described below, are exempt from being considered unbudgeted.

*Under-Funded Projects:* Projects that are submitted for approval that were included in the original approved budget, where the requested capital amount is greater than the budgeted amount for that project, must either be offset by a like reduction in one or more budgeted projects, approved by the RAC if subject to the its Charter or the additional funding requires prior written approval by the LKE CFO and CEO. These projects are considered “partially budgeted” in PowerPlan since the full funding is not coming from the original budget for that project. FP&B and/or SS&C must approve AIPs for under-funded projects (see *FP&B and SS&C Approvals* below).

*Retirement Only Projects:* Any Capital project for retirement purposes only that is submitted for approval, including the retirement of assets that result in a net credit, should use a retirement work order type in the PowerPlan system. The approval levels will automatically be applied based on the size of the absolute value amount for the AIP. The approvals will be required at the Director level up to \$1,000,000 and at the CFO level at \$1,000,000 or more.

*Transfer of Assets Between Utilities:* Any Capital project proposal that results in a transfer of assets from LG&E to KU or from KU to LG&E should include a notification email to be sent for review by the Manager of Corporate Accounting, the Manager of Corporate Finance and the Manager of Property Accounting prior to being submitted for approval in the PowerPlan system.

The project set up, which includes the work order type, must be coordinated with Property Accounting before the project is sent for approval. If the transfer between utilities is for assets with an original net book value of \$1 million or more, the proponent must also notify the State Regulation and Rates department for review before the project is sent for approval.

*LG&E and KU Board and PPL approvals:* Any budget item over \$50 million requires the approval of the LG&E and KU Energy Board. Budget items over \$100 million additionally require the approval of the PPL Finance Committee. Cost overruns greater than 20% on budget items approved by the PPL Finance Committee must be re-approved by the Committee before spending occurs. If an overrun on a budget item results in a total cost of \$100 million or more, the proposal must be approved by the PPL Finance Committee before overrun spending occurs.

*Project Overruns:* When it is apparent that the amount approved on the original AIP will be

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### **Capital and Investment Review**

insufficient (project is expected to be 10% or \$100,000 over, whichever is less, subject to a

minimum of \$25,000) to complete the project, **a revised AIP must be completed and submitted in PowerPlan. The revised forecasted project cost must also be included in the capital forecast to be reviewed and approved by the RAC and IC. Additionally, when completing the revised AIP, the following conditions apply (see Capital Approval Appendix on page 10):**

- If the project is \$1,000,000 or below, no IP or CEM are required. Provide a clear explanation of the overrun in the revised AIP description upon submittal in PowerPlan.
- If the project overrun causes the total amount to exceed the next approval level, but did not exceed the 10% or \$100,000 (subject to a minimum of \$25,000) amount over the previously approved project level that requires a revised AIP, no action is required. The only exception is the IC threshold as noted below.
- If the total revised project requested is greater than \$1,000,000 but less than \$2 million, a revised IP and CEM are required with the submission of the revised AIP. If the original approved project was less than or equal to \$1,000,000 before the overrun which brings the revised project request above this threshold, an IP and CEM are now required.
- If the project overrun is expected to be \$500,000 or greater and the project had been approved by the IC, the revised project, including a revised IP and CEM, must be approved subject to the RAC Charter and presented and re-approved by the IC.
- If project overrun is \$100,000 or more, but less than \$500,000 and the project had been approved by the IC, provide a clear explanation of the drivers of the overrun in the revised AIP description upon submittal in PowerPlan. A revised IP and CEM are not required.
- If the previous project proposal was below the IC threshold and the revised amount is over the IC threshold, the revised proposal needs to be approved by the IC regardless of the increased amount. A revised IP and CEM are required.
- Project overrun must be offset by a like reduction in one or more budgeted projects, approved by the RAC if subject to the [RAC Charter](#) or the overspending requires prior written approval by the LKE CFO and CEO.
- Revised AIPs must be approved for the total revised dollar amount using the approval limits in the [Authority Limit Matrix](#).

*FP&B and SS&C Approvals:* Unbudgeted projects or those projects requiring an IP and CEM (i.e., over \$1,000,000) must include FP&B and SS&C review and approval. Unbudgeted projects less than \$250,000 require SS&C Manager approval and those \$250,000 and over require FP&B Director approval. The FP&B Director has PowerPlan system AIP approval delegation authority for the Investment Committee (whose approval is noted in Investment Committee meeting minutes or email vote) as well as for the President and CEO (whose approval is noted via signature on the IP document) and will approve AIPs in the system only after confirmation of the fully approved IP document being attached to the AIP.

Budgeted projects less than or equal to \$1,000,000 are approved as normally required by the [Authority Limit Matrix](#) and do not require the approval of FP&B and SS&C.

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

*Blankets & Miscellaneous Projects:* Homogeneous projects less than \$500,000, not able to be identified during the budgeting process, can be funded by either a blanket project or a miscellaneous project as outlined. Blanket projects are used to procure routine work, which lacks detail when preparing the budget. Blanket projects are approved annually in the 4<sup>th</sup> quarter by the Investment Committee or during the Officer review of the Capital Budget. New blanket capital projects require the approval of both Property Accounting and FP&B. To open new blanket projects, a partial AIP in the amount of \$10,000 must go through the approval process in PowerPlan. A miscellaneous project is used by each generating plant and LOB for small individual projects which arise during the year and which cannot be specifically anticipated during the budgeting process. Miscellaneous projects do not require an AIP but will be either used as the funded transfer on another project's AIP or opened and as money is spent then information detail will be provided to the Property Accounting department.

*Reimbursable Projects:* Projects which will have all or a portion of the spending amount reimbursed by an outside party must follow the same guidelines as non-reimbursable projects, except as noted below:

- Tax Department review indicating whether Contribution in Aid of Construction is taxable must occur prior to any reimbursement agreement greater than \$25,000 being finalized and evidence of such review must be attached to the AIP. This does not apply to customer refund agreements.
- If a fully executed agreement specifying the terms of reimbursement is attached to an AIP with gross spending under \$2 million, the net spending amount may be used to determine whether an IP and CEM are required.
- Third Party jointly-owned utility projects under the specified gross spending thresholds qualify for this exception without requiring the attachment of the executed joint ownership agreement.
- For all projects, the gross spending amount must always be used to determine the appropriate approval level.

*Government-Mandated/Regulatory Compliance Projects:* Projects which are not reimbursable but which are mandated by governmental legislation or other governmental authority must follow the same guidelines as all other projects except that for such AIPs with gross spending under \$2 million neither the IP nor the CEM are required, provided that the appropriate legislative docket numbers or applicable statute references are provided with the AIP.

*Preliminary Survey and Investigation:* Projects that are originally set up for preliminary survey and investigation are treated as indirect projects and are auto approved and opened in PowerPlan. All amounts recorded as preliminary survey and investigation must be capital in nature. Once the preliminary survey and investigation work is complete, the determination must be made if the project will move forward as capital or be abandoned and expensed. If the project moves forward as capital, a new project must be created in PowerPlan and must follow the approval levels based on the Authority Limit Matrix. It is the responsibility of the budget coordinator to notify Property Accounting and make the appropriate accounting transactions to move preliminary survey and

## **LG&E AND KU ENERGY LLC Policy**

Date: 4/1/2021  
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### **Capital and Investment Review**

investigation charges to capital or to expense as appropriate.

#### **Early Activation Guidelines**

In order for a project to be early activated, the following criteria must be met:

1. The expenditure must be the result of a true emergency which is defined as one of the following: 1) the expenditure is needed to address an immediate safety risk; 2) the equipment has failed; or 3) a material problem has been found, requiring it to be replaced immediately in order to maintain the reliability of the system.

OR

2. The equipment vendor has provided a quote for the capital purchase that is only valid for a short period of time. The time frame would not be long enough to complete all the necessary paperwork and acquire all necessary approvals in time to place the order at the reduced price.

Process requirements for an early activated AIP are as follows:

- For each AIP that is early activated, Property Accounting must first receive email approval from the highest level of LOB authority based on the total amount of the AIP as per the AIP approval process. FP&B and SS&C must also be copied on this email. Should the AIP be for an unbudgeted project, approval from FP&B and SS&C will be required for the early activation.
- In the event the project has been previously approved by the IC, the above email from the highest LOB authority would not be required. Instead, verification from FP&B that the project had indeed been approved by the IC would be sufficient approval.
- The approval request email must include the following information:
  - Project number
  - Project description
  - Total project amount
  - Name of the individual whose highest level of authority is required, and any associated delegation of authority (DOA)
  - Description of the need for the early activation
  - For an unbudgeted project, the budgeted project number that will cover the unbudgeted spending.
- Additionally, for either scenario 1 or 2 above, an automated AIP must be submitted for \$10,000 and approved by the project manager and budget coordinator for the project in order for the project to be moved to “open” status in PowerPlan.
- Property Accounting will maintain a log of early activated projects, and copies of the email approvals will be filed with the AIP.

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

- A revised AIP (for the full project amount) for all projects that are early activated must be received by Property Accounting, or FP&B if necessary, with all required approvals, as soon as possible, but no later than 30 business days after the early activation. Repeated failure to comply with this timing may require email approval by the appropriate LOB VP for early activation of all future AIPs.

### **Project In-Service and/or Completion**

Upon project in-service and/or completion, the project manager or budget coordinator most familiar with the project is required to do the following:

1. Verify completion date (if the date is not correct, it needs to be updated in PowerPlan). Entering a completion date changes the project status to “completed”.
2. Verify actual in-service date (if the date is not correct, it needs to be updated in PowerPlan). Entering an in-service date without a completion date changes the project status to “in-service”. Verify actual installed costs and actual removal costs (report/explain any variances greater than 10% from the AIP to Property Accounting).
3. Verify units of property installed and units of property retired (report to Property Accounting if different from AIP).

### **Leases**

Prior to the execution of any new lease entered into on behalf of the Company, a review must be conducted by the budget coordinator for the appropriate LOB, Regulatory Accounting and Reporting and the Tax department to determine if the lease is structured as a finance or operating lease. Additional reviews by Legal and Corporate Finance may be required depending on the total amount of the lease. See the LKE [Lease Policy](#) for more details.

**Penalties for Noncompliance:** Failure to comply with this policy may result in disciplinary action, up to and including discharge.

**Reference:** [Authority Limit Matrix](#); [CEM](#); [Lease Policy](#); [Resource Allocation Committee Charter](#); [FERC Uniform System of Accounts](#); and [Investment Proposal](#) forms.

### **Key Contact:**

- Financial Planning & Budgeting
- Shared Services & Corporate Budgeting
- Accounting Matters: Property Accounting and Controller
- Capital Leases: Corporate Finance and Regulatory Accounting and Reporting

**Administrative Responsibility:** Chief Financial Officer.

Revision Dates: 12/01/07, 04/04/08, 12/31/08, 7/20/2009, 5/1/2014, 12/1/2014, 5/16/2016, 1/27/2017, 4/24/2017, 6/1/2017, 2/12/2018, 1/01/2019,5/1/2019, 2/1/2020, 2/1/2021

(See Capital Approval Appendix B for additional reference)

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## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

#### **APPENDIX A: CONSTRUCTION OVERHEADS –CAPITALIZATION POLICY AND CHARGING ACTIVITY GUIDANCE**

##### **Local Engineering**

Local engineering is used mainly by personnel in operations, including budget oversight, that are involved in capital activities related to their lines of business. Costs are accumulated in a clearing account (1846xx) and allocated to capital via the burdening process. Each line of business and the applicable budgeting functions charge costs based on the following guidelines:

##### **Budgeting Activities**

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in the A&G study):

- Capital project work (e.g. setting up, in-service, closing, etc.)
- Analysis for capital projects (Investment proposals, etc.)
- Annual Business Planning activity for capital including strategy development
- Monthly forecasting activities for capital
- Preparation of Authorized Investment Proposals (AIPs) and associated support
- Capital budget and forecast review meetings
- Investment Committee and RAC meetings preparation and support

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Non-capital project work (e.g. setting up, closing, etc.)
- Answering general questions (e.g. capital vs. O&M, budget, transfers, etc.)
- General meetings (if meeting relates to a capital project, depending on the topic, it may be appropriate to capitalize to that capital project)
- Formulating policies
- Preparing reports (e.g. FERC reports)
- Audit work
- General accounting work
- Creating and reviewing financial reports
- Training

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

#### **Generation Activities**

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in the A&G study):

- As-built drawings
- RFP process for capital project
- Providing work direction and oversight on capital projects
- Development of new material or construction standards
- Contract activity for capital projects
- Inspecting multiple capital jobs
- Job closing
- New mapping of installed assets
- Design work on capital projects
- Detailed design/technical review of capital projects
- Scheduling crews working on capital projects
- Investment Committee and RAC meetings preparation and support
- Site visits
- Locating for capital activities\*

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Editing or updating existing construction standards
- Relocating of facilities without replacements of retirement units
- Oversight of maintenance activities
- Oversight of general operations (e.g. meetings)
- Failed material analysis
- Analysis to determine condition (e.g. repair or replace)
- Locating for maintenance activities\*

\* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering.

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## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

#### **Electric Transmission Activities**

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (if not included in the A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets
- Inspecting multiple capital jobs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC meetings preparation and support
- Scheduling crews working on capital projects
- Site visits
- Providing work direction on capital projects
- Locating for capital activities\*

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Oversight of maintenance activities
- Relocating of facilities without replacements of retirement units
- Editing or updating existing construction standards
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Coordination of maintenance activities (e.g. development of maintenance standards, coordination of crews to perform maintenance activities, answering maintenance questions)
- Oversight of general operations (e.g. meetings)
- Approving change orders
- Failed material analysis
- Locating for maintenance activities\*
- Line patrol

\* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering.

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

#### **Electric Distribution Activities**

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets
- Inspecting multiple capital jobs
- CPC designs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC preparation and support
- Scheduling crews working on capital projects
- Site visits
- Providing work direction on capital projects
- Locating for capital activities\*

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Oversight of maintenance activities
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Editing or updating existing construction standards
- Feeder phase rebalancing
- Relocating of facilities without replacements of retirement units
- Line patrol
- Coordination of maintenance activities (e.g. development of maintenance standards, coordination of crews to perform maintenance activities, answering maintenance questions)
- Oversight of general operations (e.g. meetings)
- Approving change orders
- Failed material analysis
- High level review of scoping memos and design concepts
- Analysis to determine condition (e.g. repair or replace)
- Locating for maintenance activities\*

\* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering

## **LG&E AND KU ENERGY LLC Policy**

### **Capital and Investment Review**

#### **Gas Activities**

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets
- Inspecting multiple capital jobs
- CPC designs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC preparation and support
- Scheduling crews working on capital projects
- Site visits
- Locating for capital activities\*
- Site visits

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Line Patrol
- Failed material analysis
- Approving change orders
- Evaluating repair/replace scenarios
- Surveys (e.g. leak or atmospheric)
- Pressure monitoring and recording
- General inspections
- Updating device settings or equipment adjustment
- Analysis to determine condition (e.g. repair or replace)
- Editing or updating existing construction standards
- Relocating of facilities without replacements of retirement units
- Oversight of maintenance activities
- Oversight of general operations (e.g. meetings)
- High level review of scoping memos and design concepts
- Leak repair not involving retirement units
- Locating for maintenance activities\*

\* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering

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## **LG&E AND KU ENERGY LLC Policy**

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### **Capital and Investment Review**

#### **Administrative and General study (every two years)**

Per the Uniform System of Accounts and NARUC Interpretation No. 59, periodic studies must be performed to determine the percentage of administrative and general costs capitalized to construction. Capitalized costs are required to have a provable relationship to construction activities. The purpose of this survey is to determine the percentage of FERC accounts 920 (Administrative and General Salaries) and 921 (Administrative Office Supplies and Expenses) that should be allocated to construction and other non-operating expenses.

Every other year, a survey is sent to the Line of Business Budget analysts supporting those departments charging time to FERC Account 920 and will be used as the basis to allocate a portion of costs to construction activities. The survey requests information by company and applicable expenditure organizations with data provided as a percentage of labor. The survey includes only expenditure organizations that had a combined total labor for LG&E and KU of \$100,000 or more charged to FERC account 920 for the most recent 12-month calendar year prior to the survey year.

The type of work included in the analysis to compute an accurate percentage for time spent supporting capital projects should align with the guidance for local engineering. In addition, accounting and financing activities associated with capital activity should also be considered including the processing of AIPs, unitization of projects, risk management and debt issuances.

Each month, Regulatory Accounting and Reporting will prepare an entry to credit FERC account 922 and debit the Administrative and General clearing account. This amount in the clearing account will be allocated to capital projects via the burdening process. Rates will be calculated and monitored in accordance with the Oracle Burdening Process Accounting policy.

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## LG&E AND KU ENERGY LLC Policy

### Capital and Investment Review

#### APPENDIX B

##### General Approval Requirements

<u>Investment</u>	<u>Action Required</u>
> \$5k	<ul style="list-style-type: none"> <li>• AIP required</li> <li>• various approvals – see ALM</li> </ul>
> \$1m	<ul style="list-style-type: none"> <li>• Investment Proposal required</li> <li>• CEM required</li> <li>• AIP required</li> <li>• Senior Officer approval and others noted in ALM</li> </ul>
> \$2m (for Real Property > \$500k)	<ul style="list-style-type: none"> <li>• Investment Committee approval and above mentioned items</li> <li>• LKE CEO approval needed</li> </ul>
> \$50m	<ul style="list-style-type: none"> <li>• Investment Committee approval and above mentioned items</li> <li>• LGE and KU Energy Board approval needed</li> </ul>
> \$100m	<ul style="list-style-type: none"> <li>• Investment Committee approval and above mentioned items</li> <li>• LGE and KU Energy Board approval needed</li> <li>• PPL Finance Committee approval needed</li> </ul>

Note: IT approval is needed for any IT project

##### Project Overruns

If a project is expected to be 10% or \$100k over, whichever is less, subject to a minimum of \$25k, a revised AIP must be completed before the overrun occurs and the following conditions apply for the revised approval request:

<u>Initial Investment Amount</u>	<u>Increase</u>	<u>Action Required</u>
< \$1m	Will bring project over \$1m for the first time	<ul style="list-style-type: none"> <li>• Investment Proposal required</li> <li>• CEM required</li> <li>• Revised AIP</li> </ul>
	Will bring project over IC threshold	<ul style="list-style-type: none"> <li>• Investment Proposal required</li> <li>• CEM required</li> <li>• Revised AIP</li> <li>• IC Approval required</li> </ul>
> \$1m and Under IC Threshold	> \$100k or 10%, whichever is less, subject to a minimum of \$25k	<ul style="list-style-type: none"> <li>• Revised IP required</li> <li>• Revised CEM required</li> <li>• Revised AIP</li> </ul>
	Will bring project over IC threshold	<ul style="list-style-type: none"> <li>• Revised IP required</li> <li>• Revised CEM required</li> <li>• Revised AIP</li> <li>• IC Approval required</li> </ul>

## **LKE Policy**

**February 1, 2020**

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### **Principles Behind the Authority Limits**

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The Authority Limits are to be used as a reference guide in combination with the more detailed policies and procedures covering specific topics. Its purpose is to provide an easily accessible source of information with respect to the approval process of LG&E and KU Energy LLC (LKE or the Company). Remember to refer to the corresponding PPL and/or LKE Policies.

It is important to keep in mind the following basic concepts underlying the Authority Limits:

- I. An expenditure must be approved by the supervisor in direct line of authority and within his or her own budget authority. If the specified level employee is not available to approve and has not provided an appropriate delegation of authority, then the next higher management level approval must be obtained.
- II. Managers and above can delegate up to their authority limit. Approval authority held by the employee may be delegated to another employee in accordance with certain LKE policy restrictions and reservations. See note 33 in this document for requirements associated with delegation of authority.
- III. LKE subsidiary delegations must not give contractors or third parties power to commit the company to any obligation without the express written approval of the CEO. This is not intended to capture the procurement or use of company owned supplies by contractors in meeting their obligations under a contract with the Company.
- IV. All company names and position titles are LKE unless stated otherwise.
- V. Investment proposals, contract proposals and payments must not be split in order to avoid obtaining the necessary approvals. All linked/inter-dependent investments must be presented in one proposal.
- VI. The form of authorization must be in writing through signature or email and as prescribed by other policies and procedures. Authorization should be maintained within the system of record where practical or otherwise retained by the applicable line of business.

Responsible Officer: Chief Financial Officer.

	Individual Contributor	Suprvr/ Team Lead/ Group Lead	Manager	Director/ General Mgr.	Vice President/Officer	VP – Human Resources	Senior Officer (1)	General Counsel	CFO	Investment Committee (2)	CEO	LKE Subsidiary Board (as applicable)	LG&E and KU Energy Board (3)	PPL New Subsidiary Group	PPL Treasury	PPL VP HR&S	PPL General Counsel	PPL Corporate Leadership Council	Nominating Committee	PPL Compensation, Governance, and	PPL Finance Committee (4)	PPL Audit Committee
<b>X = Minimum Authority Required</b>																						
<b>General:</b>																						
-- Capital Plans and Annual Budgets for LKE;													X								X	
-- Audit Engagement Letter;																						X
-- Remuneration of external auditors and any recommendation for appointment or change of appointment of auditors for all controlled companies in LKE (5);																						X
-- Significant accounting policies as disclosed in financial statements filed with the SEC (all accounting policies must be consistent with the required standard applied by the relevant regulatory authorities);													X									X
<b>Appointments</b>																						
-- Appointments to the LKE Board;													X									
-- Appointments to Subsidiary Boards (6);												X										
-- Appointment of Any Representative or Agent (7).											X											
<b>Structure</b>																						
-- Creation of any subsidiary, or the participation in any consortium, joint venture or other business;												X	X	X								
-- Equity transactions of all subsidiaries of LKE in excess of \$10,000,000 (with copy to PPL Treasury)												X	X									
-- Changes to the management and control structure of LKE and the Major Subsidiaries, including changes to company and business names (6);												X	X						X			
-- Changes to, or unbudgeted investments outside of the core business of LKE:																						
-- up to \$50,000,000													X									
-- over \$50,000,000													X									X
-- New Entities: Formation, Acquisition or Disposition of a New Entity or Subsidiary (8):																						
-- up to \$75,000,000											X			X								
-- over \$75,000,000												X	X	X								X
<b>Treasury Transactions</b>																						
-- Awarding of <i>Banking Business</i> to banks not within the relationship group of banks;									X						X							
-- Opening and closing bank accounts					X				X						X							
-- Establishment of electronic money transmission systems					X				X						X							
-- External financing transactions: (10)																						
-- up to \$10,000,000									X													
-- up to \$50,000,000													X	X								
-- over \$50,000,000													X	X								X

	Individual Contributor	Suprvr/ Team Lead/ Group Lead	Manager	Director/ General Mgr.	VP - Human Resources	Senior Officer (1)	General Counsel	CFO	Investment Committee (2)	CEO	LKE Subsidiary Board (as applicable)	LG&E and KU Energy Board (3)	PPL New Subsidiary Group	PPL Treasury	PPL VP HR&S	PPL General Counsel	PPL Corporate Leadership Council	Nominating Committee	PPL Compensation, Governance, and	PPL Finance Committee (4)	PPL Audit Committee	
<b>X = Minimum Authority Required</b>																						
-- Redemptions, repurchases, retirements, defeasances and other methods of reducing outstanding securities (does not apply to scheduled repayments of debt or financing transactions within the LKE group or involving PPL affiliates (such latter transactions must be coordinated with PPL Treasury)): (10)																						
-- up to \$10,000,000								X														
-- up to \$100,000,000											X	X										
-- over \$100,000,000											X	X									X	
-- Intra-group financing transactions within the LKE group or with PPL affiliates (the latter requiring coordination with PPL Treasury)								X														
-- The circumstances in which External currency and interest rate transactions can be concluded												X		X								
-- Setting of External credit limits exceeding \$25,000,000 (9)												X		X								
-- Guarantees or other credit liquidity support: (10, 32)																						
-- up to \$10,000,000								X														
-- up to \$50,000,000											X	X										
-- over \$50,000,000											X	X									X	
<b>Investments (11, 31)</b>																						
<b>Investment Proposal (12)</b>																						
Up to \$25,000		X																				
Up to \$100,000			X																			
Up to \$500,000				X																		
Up to \$1,000,000					X																	
Up to \$2,000,000						X																
Up to \$50,000,000								X	X													
Up to \$100,000,000								X		X	X	X										
Over \$100,000,000								X		X	X	X									X	
<b>Real Property-Related Transactions (including purchases, sales, transfers or amendments of deeds, leases, sub-leases, easements, rights-of-way, mineral rights, liens, etc.) (13, 31)</b>																						
Up to \$250,000					X																	
Up to \$500,000						X																
Up to \$50,000,000								X	X													
Up to \$100,000,000								X		X	X	X										
Over \$100,000,000								X		X	X	X									X	

	Individual Contributor	Suprvr/ Team Lead/ Group Lead	Manager	Director/ General Mgr.	Vice President/Officer	VP – Human Resources	Senior Officer (1)	General Counsel	CFO	Investment Committee (2)	CEO	LKE Subsidiary Board (as applicable)	LG&E and KU Energy Board (3)	PPL New Subsidiary Group	PPL Treasury	PPL VP HR&S	PPL General Counsel	PPL Corporate Leadership Council	Nominating Committee	PPL Compensation, Governance, and	PPL Finance Committee (4)	PPL Audit Committee
X = Minimum Authority Required																						
<b>Contracts (11, 14, 15, 31)</b>																						
<b>Competitively Bid Contracts, Contract Purchase Agreements &amp; Purchase Orders (Non-Power Supply, Non-Fuel and Non-Gas Supply)</b>																						
Up to \$1,000 (16)	X																					
Up to \$10,000		X																				
Up to \$100,000			X																			
Up to \$500,000				X																		
Up to \$2,000,000					X																	
Up to \$10,000,000							X		X													
Up to \$100,000,000										X	X											
Over \$100,000,000										X	X	X										X
<b>Sole Source Awards (Non-Power Supply, Non-Fuel and Non-Gas Supply) (17)</b>																						
Up to \$1,000 (16)	X																					
Up to \$10,000		X																				
Up to \$50,000			X																			
Up to \$150,000				X																		
Up to \$500,000					X																	
Up to \$2,000,000							X		X													
Up to \$100,000,000										X	X											
Over \$100,000,000										X	X	X	X									X
<b>Commodity Transactions by Power Supply (18, 19, 20)</b>																						
Up to \$400,000	X																					
Up to \$1,000,000		X																				
Up to \$2,000,000			X																			
Up to \$10,000,000				X																		
Up to \$20,000,000					X																	
Up to \$25,000,000							X															
Up to \$100,000,000										X	X											
Over \$100,000,000										X	X	X	X									
<b>Contracts for Corporate Fuels and By-Products and Gas Supply (18, 19, 21, 22)</b>																						
Up to \$10,000,000			X																			
Up to \$20,000,000					X																	
Up to \$25,000,000							X															
Up to \$180,000,000									X		X											

	Individual Contributor	Suprvr/ Team Lead/ Group Lead	Manager	Director/ General Mgr.	Vice President/Officer	VP – Human Resources	Senior Officer (1)	General Counsel	CFO	Investment Committee (2)	CEO	LKE Subsidiary Board (as applicable)	LG&E and KU Energy Board (3)	PPL New Subsidiary Group	PPL Treasury	PPL VP HR&S	PPL General Counsel	PPL Corporate Leadership Council	Nominating Committee	PPL Compensation, Governance, and	PPL Finance Committee (4)	PPL Audit Committee
X = Minimum Authority Required																						
Over \$180,000,000										X		X	X									
<b>Payments</b>																						
<b>Fuel, Gas Supply and Power Supply Payments (23)</b>																						
Up to \$100,000			X																			
Up to \$5,000,000 (copy to Director)			X																			
Up to \$10,000,000 (copy to CFO)				X																		
Up to \$100,000,000 (copy to CEO)									X													
Over \$100,000,000												X	X									
<b>Non-Fuel, Non-Gas Supply, &amp; Non-Power Supply Payments (23)</b>																						
Up to \$1,000	X																					
Up to \$10,000		X																				
Up to \$100,000			X																			
Up to \$500,000				X																		
Up to \$2,000,000					X																	
Up to \$10,000,000						X		X														
Up to \$50,000,000							X			X												
Up to \$100,000,000											X											
Over \$100,000,000 Capital												X	X									X
<b>Legal Matters and Fees (24)</b>																						
-- Up to \$500,000 legal fees				X																		
-- Over \$500,000 legal fees								X														
-- Material matters relating to initiation, defense, or settlement of litigation or binding arbitration:																						
-- less than \$500,000 inclusive of costs (except day-to-day debt recovery or unsecured claims);				X																		
-- \$500,000 to \$2,000,000 inclusive of costs;								X														
-- \$2,000,000 to \$10,000,000 inclusive of costs;								X	X		X											
-- greater than \$10,000,000 inclusive of costs.								X	X		X						X					
<b>Tax Payments and Tax Returns</b>																						
-- up to \$2,000,000 (with copy to Director, Corporate Tax) (25)			X																			
-- up to \$10,000,000 (with copy to responsible officer)				X																		
-- up to \$25,000,000									X													
-- over \$25,000,000 (with copy to CEO, President and PPL VP Tax)									X													
<b>Company Issued Credit Cards (26)</b>																						
Request for Purchasing or Storm Card			X																			
Request for Travel & Entertainment Card				X																		
<b>Donations and Contributions (27)</b>																						
-- Up to \$3,000				X																		
-- Up to \$50,000					X																	

	Individual Contributor	Suprvr/ Team Lead/ Group Lead	Manager	Director/ General Mgr.	VP - Human Resources	Senior Officer (1)	General Counsel	CFO	Investment Committee (2)	CEO	LKE Subsidiary Board (as applicable)	LG&E and KU Energy Board (3)	PPL New Subsidiary Group	PPL Treasury	PPL VP HR&S	PPL General Counsel	PPL Corporate Leadership Council	Nominating Committee	PPL Compensation, Governance, and	PPL Finance Committee (4)	PPL Audit Committee
<b>X = Minimum Authority Required</b>																					
-- Over \$50,000										X											
<b>Employee Reimbursements (28)</b>																					
Other		X	X																		
Foreign Travel						X															
<b>Petty Cash</b>																					
To Establish Petty Cash Fund			X					X													
Petty Cash Receipts/Reimbursement/Fund Reimbursement			X																		
<b>Human Resources</b>																					
New Broad-based Compensation Plans and Programs										X											
Executive annual incentive compensation awards, goals and results										X										X	
Compensation for Section 16 officers																				X	
Annual Salary Plan										X											
Team Incentive Awards (TIA) percentages, goals and results										X											
Equity Grants -- Long-term incentive grants																		X			
Benefits Plan -- Any changes in pension plans (other than changes required to remain in compliance with legal or regulatory changes).												X									
Offsite Seminars & Conferences			X																		
Executive Education Programs					X	X															
Professional Certification, Review Courses, and Examination Fees (29)			X																		
Tuition Reimbursement (29)			X																		
Relocation Approval (29)		X	X																		
<b>Personnel Changes</b>																					
Requisition for Personnel		X	X																		
Request for Temporary Employees, Co-op Students & Interns		X	X																		
<b>Offers of Employment and Promotions to:</b>																					
Employees (30)		X	X																		
Senior Management (30)						X	X														
Officers (30)										X											
Executives (30)										X					X						
Transfers and Terminations		X	X																		
Salary Increases (30)		X	X																		

## **LKE Policy**

**February 1, 2020**

### **Notes**

1. Senior officers include: CEO; COO; CFO; General Counsel/Chief Compliance Officer/Corporate Secretary
2. The following process applies to all matters submitted to the Investment Committee:
  - a. The Investment Committee also approves (i) cost overruns greater than or equal to \$500K of previously approved investment proposals; and (ii) cost overruns less than \$500K where investment proposal amount then exceeds Investment Committee thresholds.
  - b. Unbudgeted investment proposals and non-power supply, non-fuel and non-gas supply contracts fall under the procedures of the Resource Allocation Committee.
  - c. A draft of all proposals to the Investment Committee must be sent to Financial Planning and Analysis ten business days ahead of the Investment Committee meeting. Any additional material to be presented at the Investment Committee meeting (e.g. presentation) must be sent to Financial Planning and Analysis at least five business days ahead of the meeting.
  - d. Contracts that are brought to the Investment Committee must be reviewed and approved by Supply Chain (if applicable to Supply Chain), Financial Planning and Analysis, Legal, Audit Services, and Project Engineering/Generation/Environmental (if applicable to Project Engineering or Generation) prior to submission to the Investment Committee, and a copy provided to Financial Reporting to be reviewed. Additionally, in compliance with accounting guidelines, all contracts greater than \$1,000,000 must be submitted to Financial Reporting.
3. No LG&E and KU Energy Board approval needed if investment already approved by Board via budget approval or other resolution.
4. No PPL Finance Committee approval needed if investment/contract/financial transaction already approved by PPL Finance Committee via budget approval or other resolution. This exemption applies only if all contract spend is included within the 5-year approved Capital plan. Cost overruns >20% on contracts or projects >\$100,000,000 go to the PPL Finance Committee. If overrun causes initial exceedance of PPL Finance Committee authority criterion, project would go to the PPL Finance Committee at that time.
5. The conduct of all relationships (including Terms of Engagement) with external audit consultants, other than the independent auditor, must be managed through the LKE Audit Services Department. Engagement of external audit consultants must be approved by the Director, Audit Services.
6. Subsidiary board appointments shall also conform with necessary corporate law requirements. Major subsidiaries are Louisville Gas & Electric Company and Kentucky Utilities Company.
7. Other than sales agents for normal retail products and services or for customs, brokerage, service-of-process and similar agents in the ordinary course of business. All such appointments must be documented.
8. Acquisition, divestment or change of ownership interests in any new legal entities, including in consideration for sales, purchases, contributions or donations, must be coordinated with Accounting, Legal, Tax, Financial Planning and Analysis and Treasury. Also includes acquisition or disposition of minority interests in JVs, partnerships, LLCs, foundations, etc.
9. For setting of external credit limits up to \$25M, refer to credit policy for Energy Supply and Analysis.
10. The Treasurer will coordinate such activity with PPL Treasury. Guarantees or other credit or liquidity support requiring board approval relate just to such guarantees or support on behalf of a subsidiary or a non-subsidiary, not for an entity's existing, direct obligations.
11. All investments and contracts involving the handling of the Company's electronic information outside the Company's IT systems and networks must be presented to the IT Business Relationship Manager for the Line of Business and IT Security Operations for review and approval in accordance with the External Information Storage Framework.
12. Investment Proposals include:
  - a. Capital expenditures;

- b. Disposal of assets or investments; and
  - c. O&M expenditures or increases in working capital of an "investment nature". Examples could include modification of assets to improve performance, expenditures in IT systems that are not classified as capital, or a permanent increase in inventories to improve availability.
  - d. Lifetime costs must be valued and included in the business case for IT proposals, but are not included in determining the approval level required (i.e. only the capital investment is considered when determining what level of approval is needed).
13. Real property proposals are proposals for funding to purchase land and all things permanently attached, such as buildings, structures and improvements. All transactions in real property (utility and non-utility) must be coordinated with the Director, Operating Services and the Law Department prior to any commitment.
14. For procurement activity covered under the Purchasing Policy, only employees designated as authorized purchasing agents by the Director, Supply Chain can sign contracts or purchase orders.
15. Fixed price contract value is the sum of annual (undiscounted) value (sales or purchases) over the lifetime of the contract. Where the contract does not contain complete information to calculate a nominal value (e.g. rates specified but volume of work is not), a reasonable estimate should be made based on prior experience, planned utilization and activity included in the LKE Business Plan. For long-term contracts which do not obligate the company to any volume or are terminable at will, the value may be based on estimated amounts included in the LKE Business Plan period, rather than contract lifetime. If actual spend under the contract exceeds the authorization threshold obtained based on the original contract estimate, the next level authorization should be obtained prior to spend exceeding existing authorization. Floating (index) price contract value for Power Supply, Fuel and By-Products, and Gas Supply contracts is the sum of annual (undiscounted) value (sales or purchases) over the lifetime of the contract using the current forward market prices for the valuation. Extension of the term of an existing contract or exercise of an option to extend should be treated as a new contract and, if not competitively rebid, considered a Sole Source Agreement.
16. Certain individual contributors may have authority greater than \$1,000, but not greater than the next dollar level of approval noted in the ALM, with the approval of a vice president or above, documented in writing and on file with the Oracle System administrator.
17. Sole Source" is defined as the procurement process outside the formal bid process. Sole source awards require the following documentation:
  - a. For Corporate Fuels and By-Products, the document "Fuel Sole Source Award Documentation" is required.
  - b. For Gas Supply, the document "Summary of Bid Responses for Gas Supply" is required.
  - c. For non-fuels, Sole Source Award Documentation is required per the Purchasing Policy.
  - d. For power supply, see the Power Supply Commodity Policy for documentation requirements related to sole source awards.
18. No contracts or transactions for any of the commodities listed under Power Supply, Fuel and By-Products or Gas Supply may be entered into utilizing financial instruments including, but not limited to, forwards, futures, and/or swaps.
19. Proprietary trading activity is not currently authorized. If future business conditions warrant proprietary trading activity, approval from the CEO would be required prior to activity commencing.
20. Power Supply commodities procured from or sold to counterparties are covered in the Power Supply Commodity Policy and are as follows: Power (including physical energy, capacity, and ancillary services), Physical Natural Gas, Power Transmission, Natural Gas Transportation/Storage, Emission Allowances, Environmental Credits, and Renewable Energy Certificates. Firm power sales are not authorized.
  - a. Term and tenor limits, respectively, are as follows: Individual contributors are Scheduler 3 days / 3 days and Traders 4 days / 7 days; Supervisor - Trading 5 days / 7 days, Manager - Generation Dispatch and Trading 7 days / 7 days, Director-Power Supply 1 year / 18 months, VP Energy Supply and Analysis 3 years / 4 years, Chief Operating Officer 5 years / 6 years. Term or tenor in excess of 5 years / 6 years requires approval of the CEO. For Renewable Energy Certificates: 6 months / 6 months to allow time for completion of the certification process for this product.
  - b. Power Supply Group Real Time Personnel (as defined in the Power Supply Commodity Policy) are authorized to take any actions necessary to enter into short term commodity transactions for power and natural gas that exceed their limits stated in the ALM if such action is necessary to maintain system reliability. Maintaining system reliability may be

due to a request from Transmission Operator, Balancing Authority, or Reliability Coordinator, or required to meet NERC Standards or absent such actions, the Company would likely declare an Energy Emergency Event. Any such short term commodity transaction entered into on this basis must be reported in writing to the Director Power Supply and the VP Energy Supply and Analysis within twelve (12) hours of the transaction with a detailed explanation as to the nature of the reliability issue and why it was not possible to enter into transactions in compliance with the ALM.

21. Corporate Fuels and By-Products commodities procured from or sold to counterparties are covered in the Fuel Procurement Policies and Procedures document and are as follows: Fuel (including physical coal and fuel oil), Bulk Commodity Supplies, and all costs related to the transportation and other services associated with those commodities.
  - a. Term and tenor limits, respectively, are as follows:
    - i. Manager LG&E and KU Fuels 1 year / 2 years, Director Corporate Fuels and By-Products 1 year / 2 years, VP Energy Supply and Analysis 3 years / 4 years, Chief Operating Officer 5 years / 6 years. Term or tenor in excess of 5 years / 6 years requires approval of the CEO.
22. Gas Supply commodities procured from or sold to counterparties are covered in the Gas Supply Policy and are as follows: Physical Natural Gas and Natural Gas Transportation/Storage.
  - a. Term and tenor limits, respectively, are as follows: Gas Supply Manager 1 year / 2 years, Director, Gas Management, Planning, and Supply 1 year / 2 years, VP Gas Distribution 3 years / 4 years, Chief Operating Officer 5 years / 6 years. Term or tenor in excess of 5 years / 6 years requires approval of the CEO.
23. Inter-company payments exceeding \$500k between LKE Companies can be approved by the Controller.
24. The conduct of all relationships (including Terms of Engagement) with external lawyers must be managed through the LKE Legal Department. Engagement or termination of and fee arrangements with external lawyers must be approved by the General Counsel/Chief Compliance Officer/Corporate Secretary, Deputy or Associate General Counsel or his/her appointed designee(s).
25. Manager approval refers to a Manager within the Controller organization. Director, Corporate Tax does not need to be sent copies of tax payments less than \$100k. (Includes Payroll related payments)
26. Requests for Procurement Cards or Corporate Cards must be submitted to the Procurement and Travel Card Administrator utilizing the application forms found on the Supply Chain website. All Purchasing Cards, including Storm Cards must be approved by the Manager Supply Chain Support.
27. See LKE policy "Community Investments (Non-Foundation) and Sponsorships for additional procedures and requirements.
28. An employee cannot approve his or her own expense reimbursement. Approval must be at least one over in the line of authority.
29. Reimbursements are subject to separately published HR policies on these topics.
30. Requires two levels of management approval (i.e., one over one) and LKE Human Resources and for executives, PPL Human Resources.
31. Copies of all leases, regardless of dollar amount, must be forwarded to Regulatory Accounting and Reporting. For additional information, please see the lease policy.
32. Applies when LGE and KU Energy LLC or any subsidiary guarantees or provides liquidity support to a subsidiary or a third-party.
33. For all LGE and KU Energy LLC and subsidiary (Company) employees that need to delegate approval authority for a determined amount of time, the following general requirements must be followed:

General Requirements:

- a. It is the responsibility of all Officers and Directors to delegate authority to a responsible employee(s) in his or her area whenever he or she or the immediate supervisor will not be available to exercise authority. A Manager's authority will be assumed by his or her Director in the Manager's absence unless a specific alternative delegation is

- completed.
- b. Authority should be delegated to individuals who are competent to deal with all matters for which they have authority, and who will seek appropriate advice if they encounter anything that is new or unusual.
  - c. A person's integrity, knowledge, experience, technical competence and soundness of judgment should be considered before delegating authority to him or her.
  - d. Powers may only be delegated to regular full-time or part-time employees unless the LG&E and KU Energy LLC Chief Executive Officer specifically approves the delegation.
  - e. Prior written approval is required for permanent delegation of authority (duration longer than an absence from the workplace due to vacation, training or medical leave) by the LG&E and KU Energy LLC Chief Executive Officer or highest-ranking Officer for the relevant business unit. This approval can only be revoked by the person delegating authority or the Officer having approved such delegation.
  - f. Authority that has already been delegated once, including permanent delegations, cannot be re-delegated to a third person.

*Exercising Delegated Authority:* An employee exercising temporary delegated authority shall sign his or her name and print the delegator's name. (i.e., John Doe (sign), for Jane Smith (print).)

*Electronic Notification:*

- a. Authority must be delegated using the Delegation of Authority system on the Company intranet.  
<http://appsint/CorpApplications/DOA>
- b. An Officer or manager must copy the delegation to the Officer or Director to whom he or she reports, naming the employee to whom authority will be delegated. Officers reporting to the CEO must copy their delegations to the Assistant to the CEO rather than to the CEO.
- c. Copies of the delegation must be sent to all Officers (in the case of an Officer's delegation) and to all direct reports of the Officer, Director or Manager who is delegating authority. Officer delegations must be copied to the Assistant to the CEO rather than to the CEO. In the case of the CEO, a copy of the delegation must also be sent to the General Counsel, Chief Compliance Officer and Corporate Secretary.
- d. For verification and audit purposes, access to the intranet delegated authority on-line system is provided to Accounts Payable, Property Accounting, Cash Management, and Audit Services Departments.

## Scope

- The Resource Allocation Committee (RAC) is comprised of LG&E and KU Senior Managers from multiple business lines who develop, prioritize, and review capital spending to ensure capital budgets are prepared with consistent prioritization rankings with an aim towards optimizing capital spending across the enterprise, as well as authorizing current year budget allocation changes.

## Objectives

The RAC ensures the following:

- When capital availability is significantly constrained, reassess project priorities and make recommendations to the Investment Committee (IC).
- Balance the RAC's mission of enterprise capital optimization with an appropriate level of operational autonomy within individual areas of responsibility.
- Specific oversight of budget items >\$1m
- Recommendation of annual Business Plan to Senior Management for approval.

## Membership

The RAC is comprised of Senior Managers representing twelve departments and serves under the direction of the IC. Current representation is as follows:

- |              |                                  |                       |
|--------------|----------------------------------|-----------------------|
| • CFO        | Financial Planning and Budgeting | Heather Metts (Chair) |
| • CFO        | Supply Chain                     | David Cosby           |
| • CFO        | State Regulation and Rates       | Robert Conroy         |
| • Operations | Generation/Power Production      | David Tummonds        |
| • Operations | Safety and TT                    | Amanda Chambers       |
| • Operations | Project Engineering              | Doug Schetzel         |
| • Operations | Customer Services                | Eileen Saunders       |
| • Operations | Transmission                     | Kyle Burns            |
| • Operations | Electric Distribution            | Tiffany Koller        |
| • Operations | Gas Operations                   | Tom Rieth             |
| • IT         | Information Technology           | Priya Mukundan        |

A delegate may be assigned to vote.

## Major Responsibilities

- The RAC serves under the direction of, and makes recommendations to, the IC to ensure alignment with major goals, strategies and direction of the organization.
- Review the capital budget and monthly variance.
- The RAC should review whether the business value proposition is proportional to the level of investment and the prioritization of the projects results in the optimal capital spend across the Company.
- Review for approval the unbudgeted projects subject to the RAC approval requirements.
- Verify that changes in the five-year capital plan from year to year must be based on new facts and circumstances and supported based on the need for, and the cost effectiveness of, the projects included therein.
- Forecast and Budgeting – Corporate provides analysis/data support.

## Tenets & Procedures

- Monthly meetings scheduled, others called as needed.
- Meetings require seven voting members to have a quorum.
- Recommendations will address implications to
  - Prudent Utility Practice
  - Strategy
  - “Next Year” Capital
  - Risk Profile
- Prioritization of projects is in line with our Company mission and values – (reliability, safety and health, customer focus, diversity and engagement, performance excellence, integrity and openness as well as corporate citizenship). To classify projects and ensure prudent decision-making across all lines of business, the following categorization will be used:
  - 1 – Committed to Safety, Environmental, Regulatory Reasons or Existing System Support
  - 1A - AMI
  - 2 – Not required but High Priority
    - 2A – Utility Best Practice
    - 2B – Probable Regulatory Impact
    - 2C – Operational Enhancements with O&M hard savings
    - 2D – Standard Existing Asset Preservation
    - 2E – System Upgrade or Replacement - not end of life/support

- 3 – Projects Subject to Funding Availability
  - 3A – Utility Best Practice
  - 3B – Operational Enhancements with no O&M hard savings
  - 3D – Non-critical improvements to Existing Assets
  
- 4 – Mechanism Projects
  - 4A – ECR
  - 4B – DSM
  - 4C – Gas Tracker
  
- Specific oversight of budget items >\$1m
  - Tracking and Reporting on projects not yet released
  - Oversight of project release dates
  - Project under-run, cancellation or delay >\$1m back to RAC
  - Approval and re-allocation of unbudgeted projects > \$1m
  - Overruns subject to IC review back to RAC
  
- Recommendation of total capital forecast each month including cost of removal; budget item changes +/- \$1m formally presented; and incremental capital expenditure changes on budget items totaling >\$1m to the Investment Committee for approval.
  
- Recommendation of annual Business Plan to Senior Management for approval.

Revision Date: 1/4/2021

Division 2-16

Request:

As explained in Mr. Sorgi's testimony (at 5:13-15), PPL owns PPL Renewables, LLC and Safari Energy, LLC which own and operate solar and energy storage projects.

- a. Please state whether these companies do business in Rhode Island or the New England control area. If yes, please provide a list of the projects that these companies own or operate in Rhode Island or the New England control area; and
- b. Explain what controls are in place in PPL's accounting systems to ensure that there is no cross-subsidization of these companies with regulated revenues.

Response:

- a. Safari Energy, LLC affiliates own several solar projects in Rhode Island and the New England control area. Please see Attachment PPL-DIV 2-16-1 for a list of these projects.
- b. PPL's accounting system maintains all companies as separate business units in order to separate regulated from unregulated business activities. Additionally, PPL complies with the Public Utility Holding Company Act of 2005 ("PUHCA 2005") and a 1995 order from the Pennsylvania Public Utility Commission ("PaPUC") related to the company's affiliated interest agreement. The PUHCA 2005 authorizes the Federal Energy Regulatory Commission (FERC) to review and approve the allocation of costs of a multi-state electric utility holding company to individual operating companies for certain goods and services provided by a service company to affiliates. PPL is also required to and does follow FERC rules specified in 18 CFR § 35.44 to prevent cross-subsidization. The PaPUC also provides oversight on the allocation of costs between affiliated companies and the Pennsylvania regulated businesses. The intent is to detect and disallow from jurisdictional rates any imprudently incurred or discriminatory costs from affiliate transactions between companies in the same holding company system and eliminate cross-subsidization between regulated and unregulated affiliates. These regulations and orders were used in establishing the current cost allocation practices of PPL and are the foundation of the Cost Allocation Manual ("CAM"). Compliance with PPL's CAM ensures no cross subsidization of non-regulated affiliates such as PPL Renewables, LLC and Safari Energy, LLC with regulated revenues.

Generation Name (Plant or Unit Name)	Owned By	Controlled By	Market/Balancing Authority Area	Geographic Region	In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used/To Be Used in Filing (MW)	Capacity Rating: Methodology Used: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative
Tyngsborough - 36 Norris Road	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	8/14/2019	0.333	0.333	N
Richmond - 1831 State Rd	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	8/28/2019	0.135	0.135	N
Ferrick Brothers - 113 Hale St	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	10/29/2019	0.193	0.193	N
Brooke Charter High School	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	9/12/2019	0.099	0.099	N
Winchester DPW	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	11/14/2019	0.077	0.077	N
Winchester Vinson Owen School	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	12/17/2019	0.069	0.069	N
Malden YMCA	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/17/2020	0.171	0.171	N
PBD Events	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	2/13/2020	0.346	0.346	N
2 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/15/2020	0.066	0.066	N
3 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/15/2020	0.066	0.066	N
4 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/24/2020	0.066	0.066	N
6 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/24/2020	0.066	0.066	N
7 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/24/2020	0.066	0.066	N
9 Cirrus Drive	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	1/15/2020	0.106	0.106	N
Loiacano-130 Sohler Rd	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	8/27/2020	0.673	0.673	N
15 Tech Circle	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	4/2/2020	0.993	0.993	N
Bobcat Development	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	4/21/2020	0.223	0.223	N
60 Solferino Street	Safari Energy Massachusetts 1-2019, LLC	Safari Energy Massachusetts 1-2019, LLC	ISO-NE	MA	10/23/2020	0.732	0.732	N
Temple Israel of Natick	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	4/22/2020	0.12	0.12	N
SED - Salem State-Gassett Fitness Center	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	6/9/2020	0.101	0.101	N
Cape Cod Region Transit Authority Parking Canopy	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	6/8/2020	0.36	0.36	N
Costa Realty LLC	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	5/13/2020	0.106	0.106	N
SED - Chelsea Clark Middle School - New Building	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	12/13/2019	0.042	0.042	N

SED - Tufts University-Lewis Hall-PO	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	12/30/2019	0.083	0.083	N
SED - Tufts University-Science and Engineering Center	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	12/30/2019	0.052	0.052	N
Town of Holliston - Fire Department	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	11/14/2019	0.051	0.051	N
Medford-DPW Building	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	1/23/2020	0.235	0.235	N
Waschuset-Glenwood Elementary School	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	2/13/2020	0.367	0.367	N
Waschuset-Naquag School	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	2/13/2020	0.326	0.326	N
Winthrop Middle High School	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	3/30/2020	0.228	0.228	N
Salem State - Berry Library	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	7/27/2020	0.176	0.176	N
Salem State - Marsh Hall	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	8/11/2020	0.102	0.102	N
Grafton High School	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	3/20/2020	0.372	0.372	N
CCRTA - Dennis	Safari Energy Massachusetts 3-2019, LLC	Safari Energy Massachusetts 3-2019, LLC	ISO-NE	MA	7/7/2020	0.208	0.208	N
Warren & Bigelow Electric	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	9/25/2020	0.199	0.199	N
Woburn Joyce Middle School	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	9/21/2020	0.315	0.315	N
Woburn Goodyear School	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	10/6/2020	0.106	0.106	N
Woburn Hurid Wyman School	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	10/6/2020	0.099	0.099	N
Winchester High School	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	10/6/2020	0.127	0.127	N
Stoneham Arena Ice Rink	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	11/13/2020	0.299	0.299	N
The Judge Rotenberg Edl Ctr	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	11/17/2020	0.182	0.182	N
Cape Cod Community Media Ctr	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	11/12/2020	0.354	0.354	N
ECI Realty LLC	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	10/16/2020	0.145	0.145	N
Acton Street Assets, LLC.	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	11/12/2020	0.178	0.178	N
John M Barry Boys & Girls Club	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	12/24/2020	0.103	0.103	N
Lorraine Holton LLC	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	1/21/2021	0.088	0.088	N
Weston Field School	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	12/15/2020	0.298	0.298	N
Cape Gun Works	Safare Energy Massachusetts 2-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	6/11/2021	0.146	0.146	N
1 Ashland Apartments	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	5/4/2021	0.213	0.213	N
5 Ashland Apartments	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	4/16/2021	0.17	0.17	N
8 Ashland Apartments	Safari Energy Massachusetts 4-2020, LLC	Safari Energy Massachusetts 4-2020, LLC	ISO-NE	MA	4/16/2021	0.169	0.169	N
100 New Boston	Safari Energy Massachusetts 2-2019, LLC	Safari Energy Massachusetts 2-2019, LLC	ISO-NE	MA	7/23/2020	1.285	1.285	N
960 Turnpike	Safari Energy Massachusetts 2-2019, LLC	Safari Energy Massachusetts 2-2019, LLC	ISO-NE	MA	12/8/2020	0.575	0.575	N

64 Industrial	Safari Energy Massachusetts 2-2019, LLC	Safari Energy Massachusetts 2-2019, LLC	ISO-NE	MA	12/9/2020	0.301	0.301	N
10 Merchant Street	Safari Energy Massachusetts 2-2019, LLC	Safari Energy Massachusetts 2-2019, LLC	ISO-NE	MA	12/31/2020	0.33	0.33	N
31 Commercial Street	Safari Energy Massachusetts 2-2019, LLC	Safari Energy Massachusetts 2-2019, LLC	ISO-NE	MA	2/12/2021	1.247	1.247	N
38 Draper	Safari Energy Massachusetts 5-2020, LLC	Safari Energy Massachusetts 5-2020, LLC	ISO-NE	MA	6/9/2021	5.983	5.983	
333 Strawberry	Safari Energy Rhode Island 2-2021, LLC	Safari Energy Rhode Island 2-2021, LLC	ISO-NE	RI		3.992	3.992	N
59 Tom Hardy	Safari Energy Rhode Island 1-2020, LLC	Safari Energy Rhode Island 1-2020, LLC	ISO-NE	RI	10/15/2020	0.178	0.178	N

Division 2-17

Request:

What are the fully identified and defined services the Service Company presently provides to Narragansett that it will continue to provide under the TSA? Please provide the identified list of over 200 services referenced in Mr. Dudkin's testimony (at 26:4 – 27:4). Provide a list of each service that the Service Company will provide and which service PPL will provide for Narragansett as of Day 1 following the completion of the transaction.

Response:

The "identified list of over 200 services" has been modified since the initial filing as a result of the ongoing integration and transition work by PPL and National Grid. The TSA services to be provided by National Grid are not yet fully identified and defined, and the services that PPL will provide for the operation of Narragansett also have not yet been fully identified and defined. Please refer to National Grid USA and The Narragansett Electric Company's response to data request Division 1-28 and Attachments NG-DIV-1-28-1 and NG DIV1-28-2-1 through NG-DIV 1-28-2-14. As the planning process progresses, PPL and National Grid integration teams will continue to refine TSA services required to operate Narragansett as of Day 1, as well as those functions for which PPL will have full responsibility as of Day 1.

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Division 2-18

Request:

Provide a detailed discussion of all training which the Service Company will be providing to PPL during the transition.

Response:

At this time PPL and National Grid have not finalized a detailed list of all training that the Service Company will be providing to PPL during the transition. It is anticipated that as part of the transition of services, the Service Company will be providing training for all services ultimately being transitioned to PPL. Additionally, for some of the services, PPL anticipates hiring existing Service Company employees. See also National Grid and Narragansett's response to Division 2-18.

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Division 2-19

Request:

List each position which the Service Company anticipates must be duplicated by PPL during the transition in order for there to be a complete transfer of systems, knowledge and operations between the two companies.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 2-19.

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Division 2-20

Request:

On pages 23 and 24 of Mr. Dudkin's testimony, he discusses the TSA. What contingency plans does PPL have in place to address the potential that the transition is not completed within the forecasted two-year transition period?

Response:

At this time PPL and National Grid anticipate that the transition services will be completed within the two-year transition period based upon negotiations and efforts to date. If it appears that any services will need to be provided beyond the two-year transition period, PPL and National Grid have the ability to negotiate to extend the provision of any such specific services beyond the two-year period.

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Division 2-21

Request:

As described in Mr. Sorgi's testimony (at 15:12-18), the circumstances in which TSA may be cancelled include the requirement for the WPD sale to be completed and for the PPL National Grid Transaction to be closed by March 17, 2022. Please explain in detail what occurs if either of these two requirements is not met.

Response:

Termination of the Share Purchase Agreement is only an option under certain conditions set forth in the Share Purchase Agreement. The WPD sale was completed on June 14, 2021. Therefore, this condition for termination is no longer valid.

If the Transaction is not completed by March 17, 2022, this date will be automatically extended by three months in the event closing has not occurred because the required regulatory approvals have not been obtained and all other closing conditions have been met. If closing has not occurred on or before the extended date, then either party has the right to terminate the Share Purchase Agreement. However, no party can terminate the Share Purchase Agreement if it has breached in any material respect its obligations under the Share Purchase Agreement in any manner that has materially contributed to the failure of closing to occur by such date (as it may be extended).

Division 2-22

Request:

Referencing Mr. Sobolewski's testimony at page 15, lines 16-19, please provide:

- a. A detailed list of functional areas that can be safely and efficiently transferred to PPL on Day 1; and
- b. A detailed list of the functional areas that will require more gradual transition.

Response:

- a. PPL and PPL RI refer to their responses to data requests Division 1-28, Division 1-29, Division 1-34 and Division 1-46.
- b. PPL and PPL RI refer to their responses to data requests Division 1-28, Division 1-29, Division 1-34, Division 1-42a, and Division 1-46.

PPL and PPL RI also refer to National Grid and Narragansett's response to data requests Division 2-22 and Division 1-28.

Division 2-23

Request:

Mr. Sobolewski states (at 16:3-16) that National Grid and PPL have assembled a group of officers, managers and other employees from both companies to plan, execute and coordinate the business integration and organization separation efforts for the Transaction.

- a. Explain in detail the responsibilities of Mr. Dan Davies, National Grid and Mr. Dudkin, PPL, including which individual will lead the efforts and the chain of command.
- b. Provide a copy of all transition plans, schedules and workplans.
- c. Provide a detailed list of the integration and transition topics.
- d. Provide the details of how National Grid and PPL will avoid duplication of cost recovery and accurately separate these transition costs.

Response:

- a. PPL and PPL RI refer to their response to data requests Division 1-20 and Division 1-29 and to National Grid USA and The Narragansett Electric Company's responses to data requests Division 1-29 and Division 2-23. PPL and PPL RI also refer to Attachment PPL-DIV 2-23-1, PPL's Rhode Island Integration Governance Model, and Attachment NG-DIV 1-29-3, Joint IMO/TMO Kickoff, dated April 7, 2021.
- b. PPL and PPL RI refer to their responses to data requests Division 1-20, Division 1-29, and Division 1-40 and to National Grid USA and The Narragansett Electric Company's response to data request Division 1-29.
- c. PPL and PPL RI refer to their responses to data requests Division 1-20, Division 1-29, and Division 1-40 and to National Grid USA and The Narragansett Electric Company's response to data request Division 1-29.
- d. PPL and PPL RI refer to their responses to data requests Division 1-30 and Division 1-33.

Division 2-24

Request:

Provide a detailed organizational chart depicting the PPL management team chain of command which the Narragansett personnel will report as described in Mr. Sobolewski's testimony (at 17:1-3).

Response:

At the current time PPL is still in the process of preparing a detailed organizational chart depicting the PPL management team chain of command. However, PPL has announced its leadership team for Narragansett effective upon regulatory approval and closing. Those positions are as follows.

- David J. Bonenberger will become President.
- Michele Leone will become vice president, Gas Operations.
- Alan LaBarre will become senior director, Electric Operations.
- Kristin DeSousa will become senior director, Customer Services.
- Brian Schuster will become, director, Regulatory and Government Affairs.
- Kate Hearn will become director, Finance.
- Kathy Moar will become manager, Human Resources.
- Mary Smith will become senior executive assistant.

The identification and transfer of employees that will transition on Day 1 is continuing to be developed.

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Division 2-25

Request:

Mr. Sobolewski testimony states (at 14:21 – 15:2) National Grid will help PPL continue to advance uninterrupted ongoing initiatives, projects, and dockets in Rhode Island that are underway as of the closing of the Transaction. Provide a detailed list of each of these contemplated initiatives, projects and dockets. Provide a detailed explanation of how National Grid will assure this is accomplished.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 2-25. PPL and PPL RI will supplement this response periodically throughout the pendency of this proceeding.

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Division 2-26

Request:

Please explain how the Narragansett electric distribution system facilities interconnected to National Grid's distribution facilities in Massachusetts will be separated and reintegrated following completion of the transaction. Please provide:

- a. distribution system maps indicating the system configuration before and after separation and reintegration;
- b. the detailed list of all capital projects and maintenance and expense projects associated with the separation and reintegration;
- c. a detailed cost estimate for all the separation and reintegration work; and
- d. any comprehensive separation and reintegration plan which has been prepared.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 2-26.

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Division 2-27

Request:

Referring to Mr. Dudkin's testimony (at 23:16-18), what are the estimated costs of the steps necessary to separate Narragansett from National Grid USA and integrate Narragansett into PPL, including integration of existing systems to incorporate Narragansett's operation? The response should identify and quantify such costs to the extent possible.

Response:

PPL and PPL RI currently are working with outside consultants, as well as Information Technology departments within PPL and National Grid USA Service Company, Inc. to identify and quantify costs associated with the steps necessary to separate Narragansett from National Grid and integrate Narragansett into PPL and PPL RI. PPL and PPL RI currently do not have an estimate of the costs necessary for that separation and integration. PPL and PPL RI will supplement this response once they have prepared such estimates and will identify and quantify such costs to the extent possible. However, as discussed in response to data request Division 1-30, PPL and PPL RI will segregate and maintain these costs at the PPL corporate level – and will not seek to pass them on to Narragansett customers.

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Division 2-28

Request:

Does PPL intend to seek recovery of costs necessary to separate Narragansett from National Grid USA and integrate Narragansett into PPL?

Response:

PPL and PPL RI will evaluate on a case-by-case basis whether they will seek to recover costs necessary to separate Narragansett from National Grid USA and integrate Narragansett into PPL, consistent with the guidance of the Policy Statement. PPL and PPL RI also refer to their response to data request Division 2-39.

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Division 2-29

Request:

Provide the organizational chart for the National Grid USA Service Company (Service Company) and separately delineate the portion of the organization dedicated to Rhode Island.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 2-29.

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Division 2-30

Request:

Provide the total cost to all of the operating companies for the 2020 services provided by the Service Company and separately provide the amount of the total cost allocated to Rhode Island.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 2-30.

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Division 2-31

Request:

What are the projected costs of the Integration Management Office and Transition Management Office initiatives through the end of the transition period?

Response:

PPL and PPL RI do not currently have projections for the costs of the Integration Management Office and Transition Management Office initiatives through the end of the transition period. Both PPL and National Grid are currently working on scope, schedule and estimating the ongoing internal and external costs relating to i) standing up the transition for Day 1, ii) defining and delivering the transition services, and iii) winding down and exiting the transition services.

Once PPL and PPL RI have prepared such cost projections, they will provide a supplemental response to this data request.

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Division 2-32

Request:

Mr. Sorgi states (at 16:12-14) that "PPL or its affiliates expect to extend employment offers to certain employees of National Grid USA and/or its affiliates, including National Grid USA Service Company, Inc., who currently provide services to Narragansett." Please:

- a. Explain in detail how PPL will fill the positions for each Narragansett, National Grid, or Service Company employee who does not accept a position with PPL.
- b. Provide the estimated cost to fill all of these positions, and explain whether the related costs (for example, sign-on bonuses, relocation packages, or expanded benefits) will be allocated to RI ratepayers.

Response:

- a. PPL and PPL RI are in the process of determining the positions needed for services that are currently being provided to Narragansett by National Grid USA Service Company, Inc. or its affiliates. If PPL does have positions that cannot be filled by a National Grid USA or Service Company employee, PPL would follow its normal hiring process of posting any such positions for external candidates to apply, interviewing candidates and then ultimately selecting an external candidate.
- b. Because PPL and PPL RI have not determined what positions may be needed, it has not performed an analysis of the estimated costs to fill any such positions. Further, PPL and PPL RI have not done an analysis of whether it would be appropriate to allocate such costs to Rhode Island customers because, at this point, any such costs are speculative and a determination of whether such allocation would be appropriate will be made on a case-by-case basis.

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Division 2-33

Request:

PPL has indicated it will have a President of Narragansett based in Rhode Island. Provide a proposed organizational chart for the management structure of Narragansett under PPL management, as well as a headcount of the expected management team members, including clerical and administrative support.

Response:

PPL and PPL RI refer to their response to data request Division 2-24. PPL is still determining headcount, including for clerical and administrative support.

Division 2-34

Request:

Referencing the Petition at paragraphs 10 and 11:

- a. Explain in detail how PPL will assure that transmission costs to Rhode Island rate payers will not increase over what they would have been if these assets remain with National Grid; and
- b. Given that the legal, engineering, regulatory, and other functions associated with all transmission activities in New England are currently coordinated among all of the National Grid distribution utilities, explain in detail how PPL will duplicate those economies of scale so that there is no duplication of efforts and no unnecessary charges imposed on ratepayers. Your response should address, among other things, daily, monthly and annual activities and filings and dockets at Federal Energy Regulatory Commission, the Rhode Island Public Utilities Commission, Siting Board and others.

Response:

- a. PPL and PPL RI are unable to speculate as to what transmission costs to Rhode Island ratepayers would be under continued National Grid ownership. PPL and PPL RI have not completed an assessment of the Rhode Island transmission system and are unable to predict at this time whether, or how much, it will require incremental investment or what effect any incremental investments may have on transmission rates. In any case, transmission rates are regulated by the Federal Energy Regulatory Commission ("FERC"), and all costs must be just and reasonable under the Federal Power Act ("FPA"). Interested stakeholders, including the Rhode Island Division of Public Utilities and Carriers (the "Division"), will be given an opportunity to intervene and comment on transmission rates in the relevant FERC proceedings.
- b. PPL and PPL RI are still working on their plans for incorporating Narragansett facilities, including transmission facilities, into their corporate structure, but PPL and PPL RI expect to utilize existing personnel and resources whenever possible. It is the goal of PPL and PPL RI to achieve similar levels of synergies that Narragansett experiences with National Grid. As explained in the response to Division 1-38, PPL has a proven track record of efficiently managing operation and maintenance costs. Costs will be shared among PPL's transmission owning utilities, including PPL Electric Utilities, in compliance with FERC rules. The transition period described in the response to Division 2-42 will allow for an orderly transition from National Grid to PPL.

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Division 2-35

Request:

Referring to paragraph 21 of the Petition, please provide any estimates prepared by or for the Applicants addressing the effect that the Transaction will have on the cost of the services presently provided by the Service Company to Narragansett after completion of the approximate two-year transition period.

Response:

PPL and PPL RI refer to their responses to data requests Division 1-30, Division 1-33, Division 2-36, and Division 2-39.

Division 2-36

Request:

Referring to paragraph 38 of the Petition, please:

- a. provide any available estimate of the acquisition premium that will be booked, but not recovered through rates, as a result of the Transaction;
- b. State whether the Applicants will seek to include the effect of the acquisition premium or transaction costs in the capital structure used for ratemaking purposes; and
- c. provide any available estimate of the transaction costs related to the Transaction. The response should itemize and quantify all such Transaction costs, regardless of whether PPL will seek to recover such costs in Rhode Island retail rates.

Response:

- a. PPL's current estimate of the acquisition premium is \$1.0 billion. Narragansett currently has goodwill on its books of \$725 million. The acquisition premium anticipated to be recorded by PPL will not be pushed down to Narragansett's balance sheet and will be retained on PPL's corporate balance sheet.
- b. PPL and PPL RI will not seek to include the effect of the acquisition premium or transaction costs in the capital structure used for ratemaking purposes. See PPL and PPL RI's response to data request Division 2-3. The purchase accounting journal entries, including the creation of additional goodwill/acquisition premium, will be recorded at PPL RI and will not be pushed down to Narragansett, resulting in no changes to Narragansett's books and therefore, will not be included in the capital structure used for ratemaking purposes. In addition, see PPL and PPL RI's response to data request Division 1-33. PPL will not seek recovery of transaction costs and such costs will not be included in the capital structure used for ratemaking purposes.
- c. See PPL and PPL RI's response to data request Division 1-32. At this time PPL and PPL RI do not have an estimate of what the total Transaction costs will be as they continue to assess system needs. PPL and National Grid continue to work together to ascertain that estimate.

Division 2-37

Request:

Referring to Mr. Sobolewski's testimony (at 13:13-17), although the transfer of ownership of Narragansett to PPL Rhode Island will have no impact on base distribution rates charged to Narragansett electric and gas customers upon the closing of the Transaction, is it expected that the base distribution will eventually be impacted by PPL ownership? If so, please describe and quantify the expected impact of PPL ownership.

Response:

As explained in PPL and PPL RI's response to data request Division 1-8, PPL and PPL RI expect to collaborate with the Rhode Island Division of Public Utilities and Carriers on when PPL RI will file a base distribution rate case after the transfer of ownership of Narragansett to PPL RI is completed. Once PPL RI files that base distribution rate case, PPL and PPL RI expect that the proposed rates will be based on a test year that reflects actual costs associated with PPL RI's ownership and operation of Narragansett. And, on an ongoing basis thereafter, PPL RI's proposed base distribution rates in future base distribution rate cases for Narragansett will be based on costs incurred under PPL and PPL RI's ownership and operation. Accordingly, PPL ownership will eventually impact base distribution rates once those rates are set through rate cases based on actual costs under PPL ownership.

PPL and PPL RI are unable to quantify the expected impact at this time. PPL and PPL RI expect that PPL RI's ownership will have a positive impact on rates for Narragansett gas and electric customers by maintaining lower rates than otherwise would have resulted in the absence of PPL RI's ownership based on PPL's experience operating PPL Electric Utilities Corporation in Pennsylvania. PPL and PPL RI also refer to their response to data requests Division 2-9 and Division 2-10.

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Division 2-38

Request:

Referring to Mr. Dudkin's testimony (at 22:17-20), will PPL also commit that it will not seek an increase in base distribution rates to pay for other transaction costs related to the Transaction such as advisory costs and investment banking fees?

Response:

As set forth in PPL's response to Data Request 2-39, PPL will treat transaction costs related to the Transaction such as advisory costs and investment banking fees consistent with FERC's Policy Statement issued on May 19, 2016 ("Policy Statement").

Division 2-39

Request:

Mr. Sorgi states (at 9:12-13) that PPL will not seek to recover any acquisition premium or transition cost in customer rates. Please:

- a. Define "transaction costs" and explain the extent to which the above pledge applies to costs associated with transitioning Narragansett's ownership, operations, administration and management from National Grid to PPL;
- b. Provide a detailed explanation of how these costs will be tracked and reported to assure they are not recovered in rates; and
- c. Confirm that PPL does not intend to recover from ratepayers the transition costs associated with transitioning the ownership, operations and all procedures and active docket processes from National Grid to PPL.

Response:

- a. According to FERC's Policy Statement issued on May 19, 2016 ("Policy Statement"), "transaction costs" include, but are not limited to, the following costs incurred to explore, agree to, and consummate a transaction:
  - the costs of securing an appraisal, formal written evaluation, or fairness opinions related to the transaction;
  - the costs of structuring the transaction, negotiating the structure of the transaction, and obtaining tax advice on the structure of the transaction;
  - the costs of preparing and reviewing the documents effectuating the transaction (e.g., the costs to transfer legal title of an asset, building permits, valuation fees, the merger agreement or purchase agreement and any related financing documents);
  - the internal labor costs of employees and the costs of external, third-party, consultants and advisors to evaluate potential merger transactions, and once a merger candidate has been identified, to negotiate merger terms, to execute financing and legal contracts, and to secure regulatory approvals;
  - the costs of obtaining shareholder approval (e.g., the costs of proxy solicitation and special meetings of shareholders);
  - professional service fees incurred in the transaction (e.g., fees for accountants, surveyors, engineers, and legal consultants); and

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- installation, integration, testing, and set up costs related to ensuring the operability of facilities subject to the transaction.

The Policy Statement also describes “transition costs” as a second category of costs related to mergers, which are incurred after the transaction is consummated, often over a period of years. The Policy Statement indicates that “these costs include both the internal costs of employees spending time working on transition issues, and external costs paid to consultants and advisers to reorganize and consolidate functions of the merging entities to achieve merger synergies. These costs may also include both capital items (e.g., a new computer system or software, or costs incurred to carry out mitigation commitments accepted by the Commission in approving the transaction to address competition issues, such as the cost of constructing new transmission lines) and expense items (e.g., costs to eliminate redundancies, combine departments, or maximize contracting efficiencies). The Commission proposed that such transition costs incurred to integrate the operations of merging companies include, but are not limited to, the following:

- engineering studies needed both prior to and after closing the merger;
- severance payments;
- operational integration costs;
- accounting and operating systems integration costs;
- costs to terminate any duplicative leases, contracts, and operations; and
- financing costs to refinance existing obligations in order to achieve operational and financial synergies.

The Commission stated that this list of transition costs is not exhaustive, and may include other categories of costs incurred or paid in connection with the integration of two utilities after a merger. Thus, the Commission proposed to consider transition costs as transaction-related costs that should be subject to hold harmless commitments on a case-by-case basis and that such transaction-related costs should be covered under hold harmless protection, although noting that applicants will have an opportunity to show why certain of those costs should not be considered transaction-related costs under their hold harmless commitment based on their particular circumstances. Also, the Commission proposed to consider, on a case-by-case basis, whether other costs not discussed herein should be subject to hold harmless commitments.”

As it relates to this question on transaction costs, PPL can confirm that it will not be seeking recovery of any transaction related costs. Additionally, PPL and PPL RI refer to their response to data request Division 1-33.

b. PPL has set-up separate project codes that are tracking internal labor time spent on the transaction as well as project codes that are tracking external third-party invoices for project costs that it is incurring. Additionally, these project codes are being tracked above The Narragansett

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Electric Company entity to assure that they will not be captured in rates. Through time reporting approval and invoice approval, these costs are being reviewed on a continual basis.

c. PPL and PPL RI will evaluate on a case-by-case basis whether they will seek to recover transition costs associated with transitioning the ownership, operations and all procedures and active docketed processes from National Grid, consistent with the guidance of the Policy Statement.

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Division 2-40

Request:

How does PPL plan to track the costs associated with the Transition? What controls has PPL put in place to ensure that these costs will not be included in rates?

Response:

PPL and PPL RI refer to their responses to data requests Division 1-30, Division 1-32, and Division 2-39b.

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Division 2-41

Request:

Please state whether PPL proposes a rate freeze and/or a capital spending freeze during the transition period or any future period.

Response:

PPL is not proposing a rate freeze and/or a capital spending freeze during the transition period. During the transition period PPL intends to utilize the existing ratemaking structures currently available in Rhode Island and currently being utilized by Narragansett, and PPL also intends to follow the existing capital recovery methodologies in Rhode Island such as the yearly filing of an Infrastructure, Safety and Reliability ("ISR") Plan.

Division 2-42

Request:

Referring to paragraph 13 of the Petition, please describe the expected effect of Transaction on the Integrated Facilities Agreement between Narragansett and NEP. Provide any updates of your review of the plan for post-closing, physical operation of the Narragansett transmission assets and related regulatory approvals.

Response:

During a transition period after the Transaction has closed, Narragansett-owned electric transmission assets will continue to be integrated with the electric transmission system of National Grid transmission-owning subsidiaries in New England. During this transition period, Narragansett-owned electric transmission assets will continue to be operated by NEP and will be subject to an Integrated Facilities Agreement in Schedule III-B of NEP's FERC Electric Tariff No. 1 for operational purposes and for the provision of open access transmission service. During the transition period, NEP will also continue to serve as a Participating Transmission Owner for Narragansett-owned electric transmission assets under the Transmission Operating Agreement with ISO New England Inc. At the end of the transition period, it is anticipated that: (1) Narragansett will become a separate Participating Transmission Owner that is a party to the Transmission Operating Agreement with ISO New England Inc.; and (2) Narragansett will recover its electric transmission revenue requirements under the ISO New England Open Access Transmission Tariff and will no longer recover those revenue requirements under the Integrated Facilities Agreement in Schedule III-B of NEP's FERC Electric Tariff No. 1.

PPL and Narragansett are reviewing the Transmission Operating Agreement, the Rates Design and Funds Disbursement Agreement, the ISO New England Open Access Transmission Tariff, and NEP's FERC Electric Tariff No. 1 to determine if amendments to those documents will be necessary or appropriate to reflect the circumstances when Narragansett is a separate Participating Transmission Owner. Any such amendments would require approvals from the Federal Energy Regulatory Commission. Some amendments to these documents may also require agreement of ISO New England Inc. and/or some other Participating Transmission Owners.

With respect to physical operation of Narragansett's transmission assets, during the transition period, NEP will maintain current normal and emergency transmission operations and local control center services consistent with ISO New England Inc. Operating Procedures, North American Electric Reliability Corporation and Northeast Power Coordinating Council requirements, and Good Utility Practice. PPL notes that the plan for post-closing, physical operation of the Narragansett transmission assets is undergoing ongoing review and refinement. PPL will

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supplement this response with any significant updates to the plan for post-closing, physical operation of the Narragansett transmission assets.

Also, PPL is working with National Grid to consider whether additional documentation is appropriate to address operation of Narragansett electric transmission assets during the period after the Transaction has closed until Narragansett becomes a separate Participating Transmission Owner. PPL will supplement this response to the extent it determines with National Grid that any such additional documentation is appropriate and will address in its supplemental response whether it anticipates such additional documentation would require regulatory approvals.

Division 2-43

Request:

On page 9, line 10 of Mr. Dudkin's testimony, he indicates that PPL continuously analyzes its infrastructure. Please:

- a. Describe the types of analyses PPL conducts to achieve this objective and provide examples of the studies and documents prepared, including all modeling procedures.
- b. Provide any studies, reports, or other Documents prepared by PPL comparing the analyses referenced in Mr. Dudkin's testimony (at 9:7-15) to the National Grid Electric Infrastructure, Safety, and Reliability Plan and Gas Infrastructure, Safety, and Reliability Plan.

Response:

a. PPL Electric PPL Electric conducts several types of analyses of its assets and infrastructure, including but not limited to, predictive health, risk, and cost benefit analyses. PPL Electric's asset health and risk-based analyses explore multiple data sources to determine leading causes of asset failures. These causes and key findings are then weighed against risks, including, but not limited to, safety, reliability impact to customer, customer exposure, and loading to effectively prioritize and plan necessary remediations or improvements. These analyses inclusively support PPL Electric in making prudent investment decisions to ensure the most cost-effective, reliable solutions for its customers. Please see Attachment PPL-DIV 2-43-1 for an example of a data analytics project for disconnect switches.

PPL Electric also conducts routine transmission studies to aid in the creation of our long-term transmission plan. These studies include Steady State Network Analyses conducted at varying load levels. A list of these studies can be found in Table 1-1 in the PPL Planning Criteria document (<https://www.pjm.com/-/media/planning/planning-criteria/ppl-planning-criteria.ashx>). The document also includes information on study methodology, assumptions, and criteria used to bound the studies.

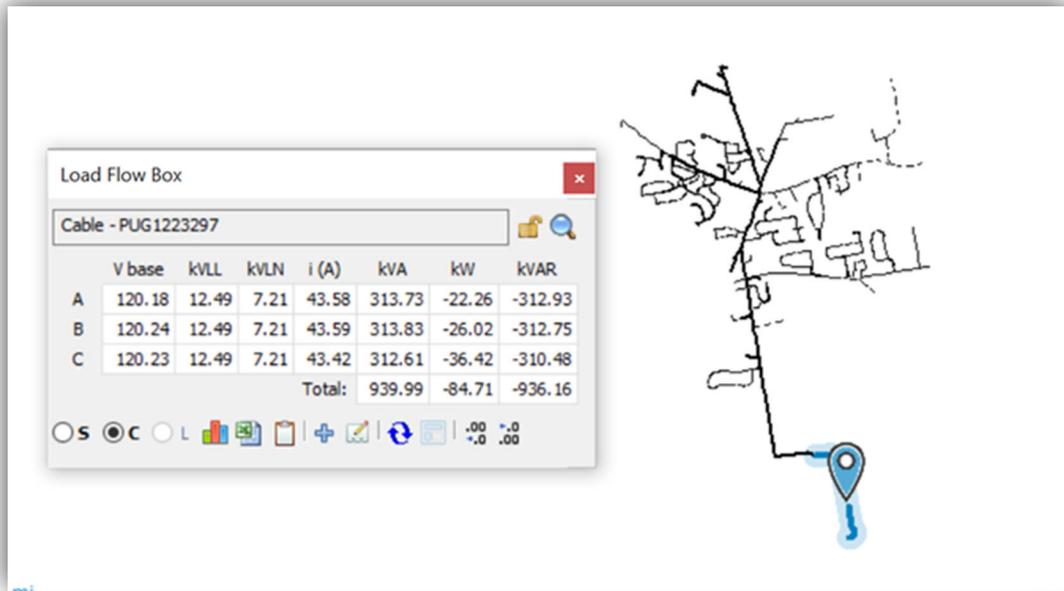
Lastly, PPL Electric conducts semiannual CYME studies of its distribution feeders. These studies are conducted to verify feeder loading and voltage. If any anomalies are identified during this process, a job is created to address the violation with a short-term solution and/or a capital investment project that mitigates the violation with a long-term solution. An example screenshot of a CYME study is below.

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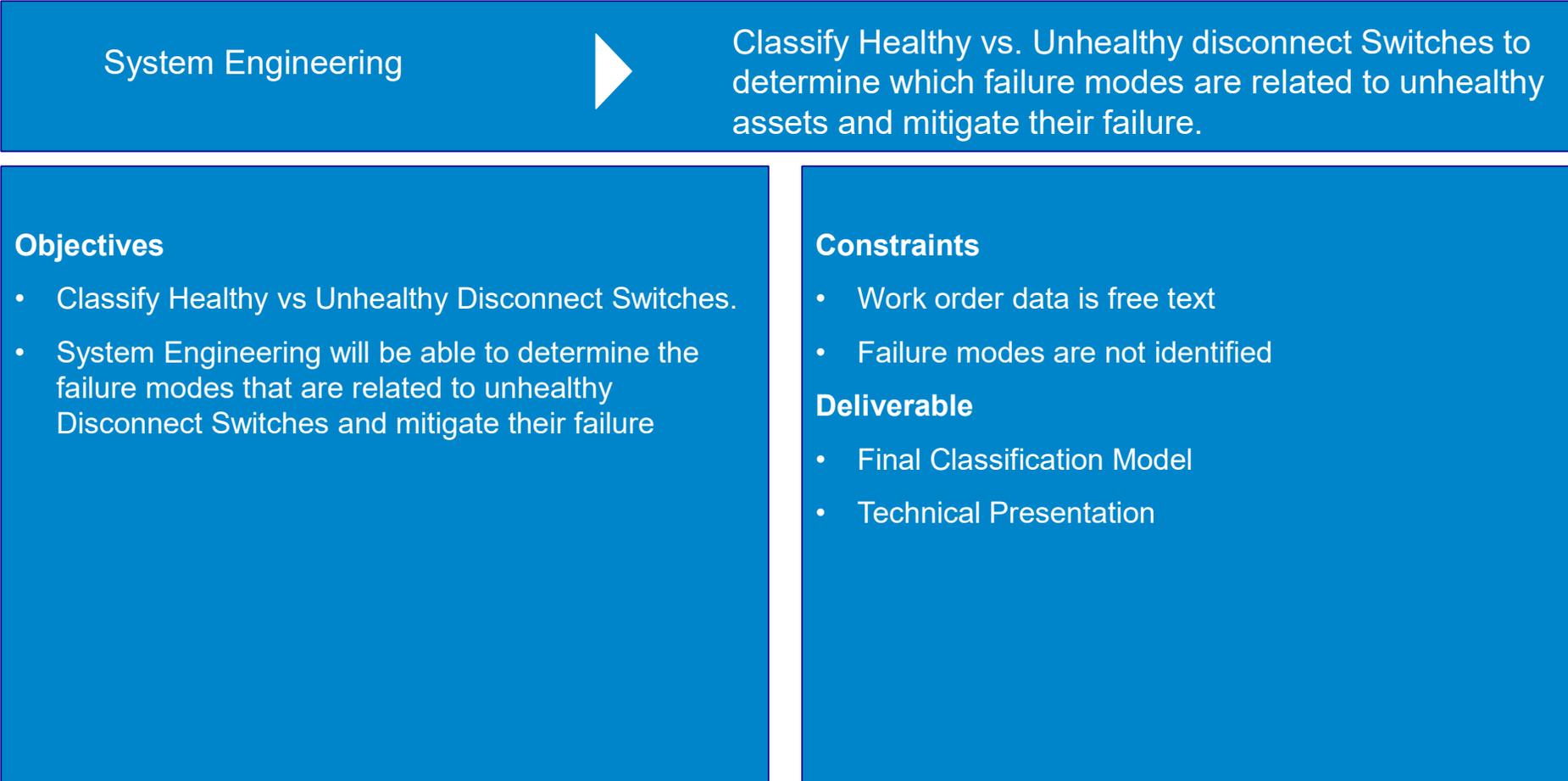


b. PPL and PPL RI do not currently have any documents responsive to this request for any studies, reports, or other Documents prepared by PPL comparing the analyses referenced in Mr. Dudkin's testimony (at 9:7-15) to the National Grid Electric Infrastructure, Safety, and Reliability Plan and Gas Infrastructure, Safety, and Reliability Plan.

# Disconnect Switches Statistical Modeling – Final Deliverable Data Analytics

*Neveen Omran | Juan Vazquez  
January 2021*

# Problem Statement



# Data Sources



Cascade T&S  
Asset Repository

Cascade T&S  
Historical Reports

ORCA Data

- Nameplate Info:
- Location
  - Position
  - Region
  - Manufacturer
  - Model
  - Install Dates
  - Equipment Number
  - Model
  - PPL Category Number
  - Rating

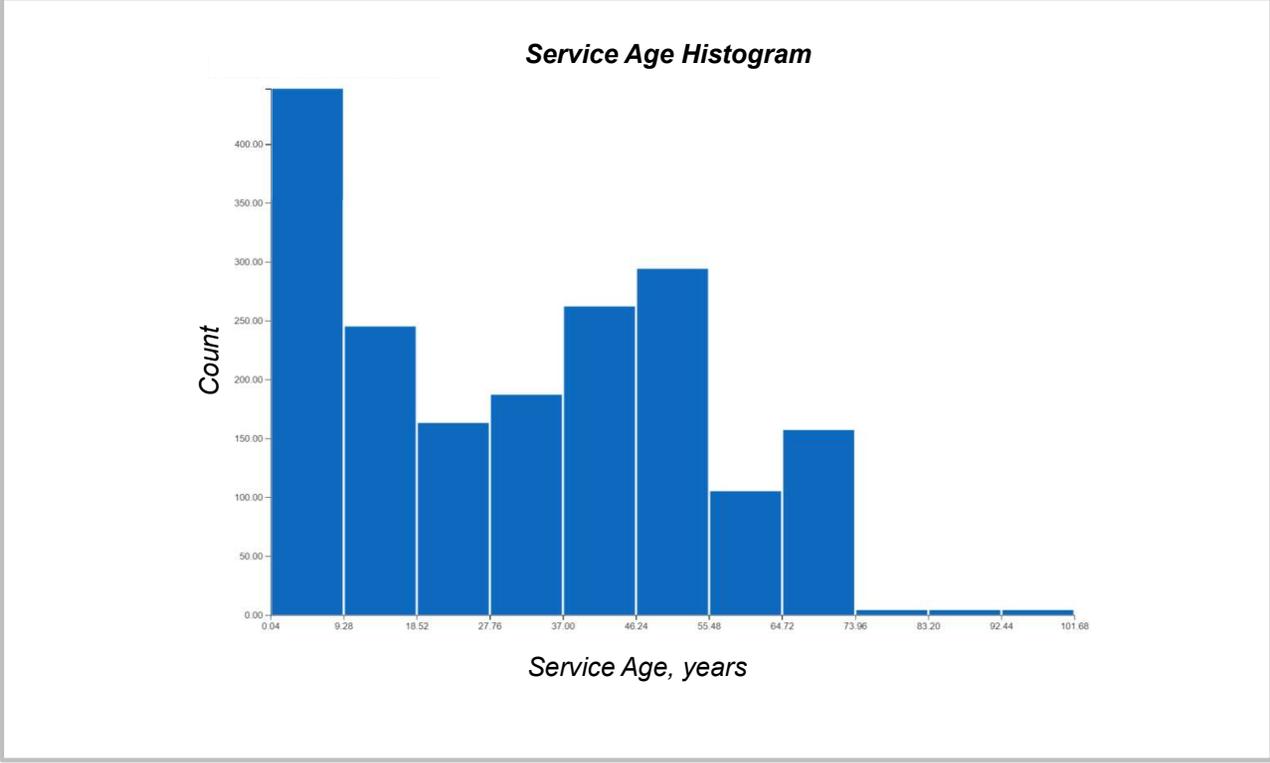
- Manual WO's:
- Repair Count
  - Unplanned Count
  - Total Work Orders
  - Hours
  - Dollars

- Switching Counts



**Predictive Model**

# Fleet Population Summary

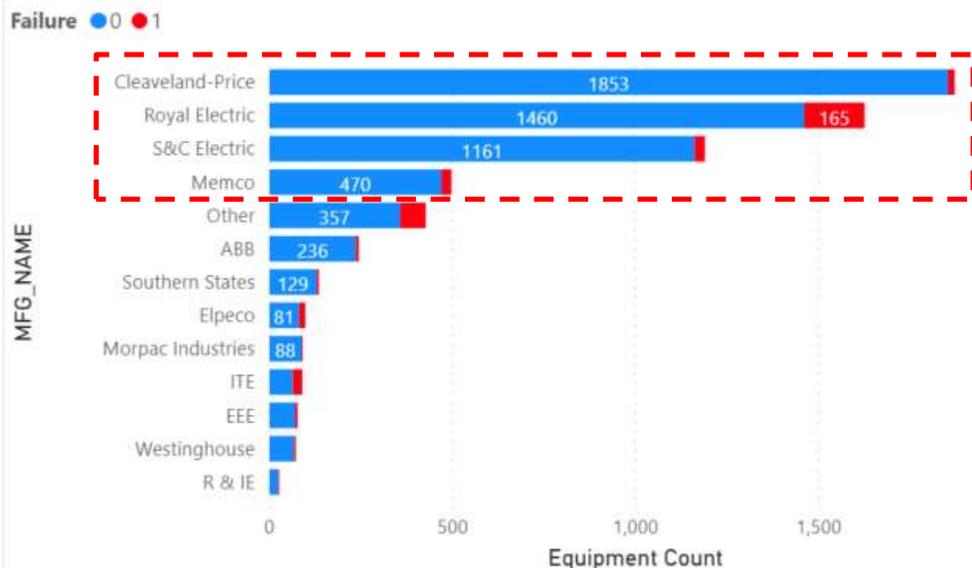


**Load Break  
Disconnect Fleet**

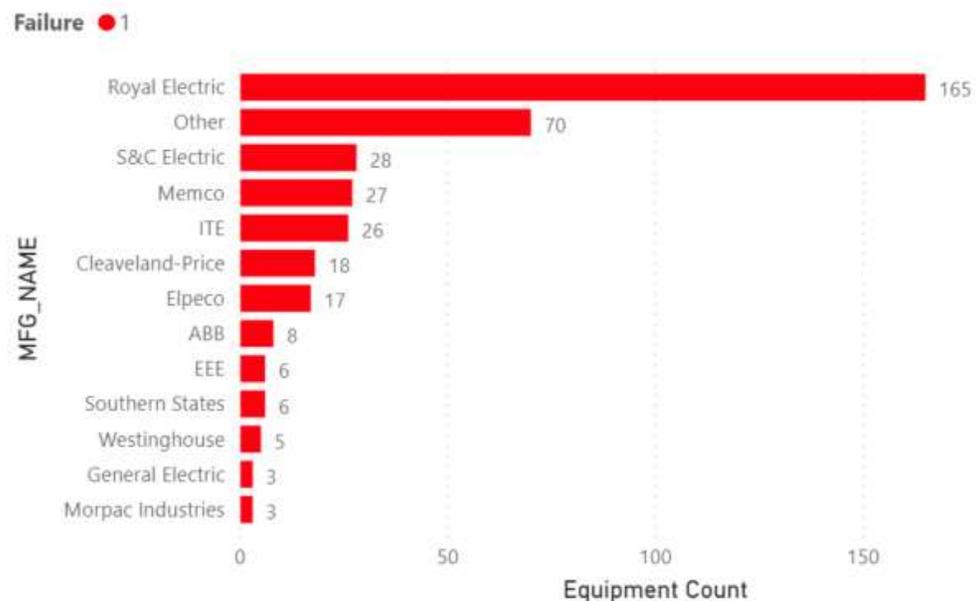
- In-Service: 5174
- Retired: 1414
- Failures: 390

# Failures

Manufacturers by Failures



Manufacturers by Failures

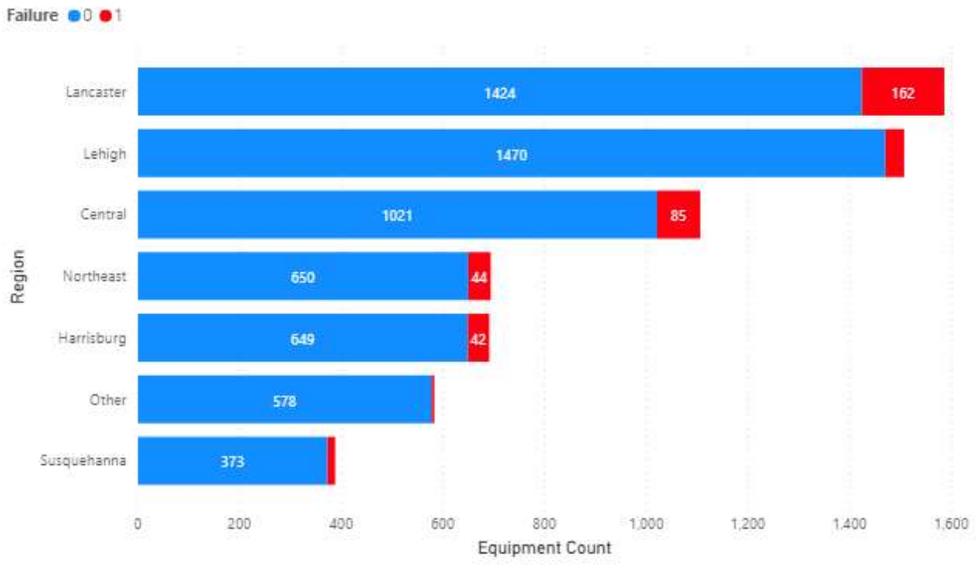


Failures driven by:

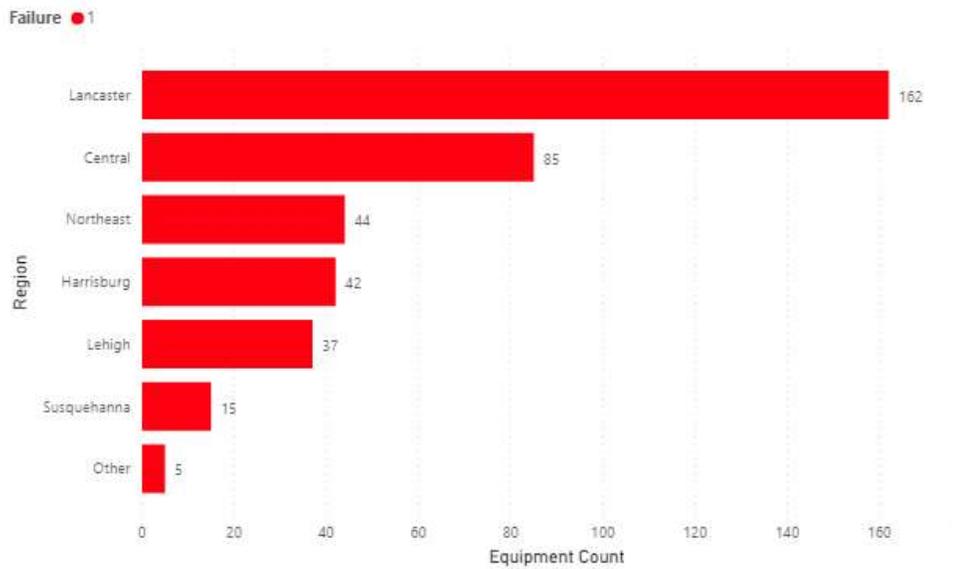
- Royal Electric, S&C Electric & Memco

# LBD Fleet by Region

Regions by Failures



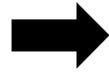
Regions by Failures



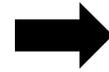
LBD by Region  
 (Inservice and Spares)

# Statistical Modelling Process

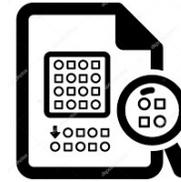
Data Sources



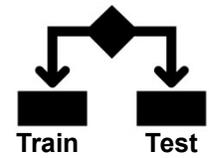
LBD Asset Attributes



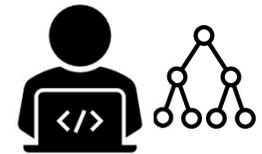
Feature Engineering



Split / Sampling



Run Algorithm



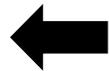
Random Forest



Evaluate Model



Key Insights



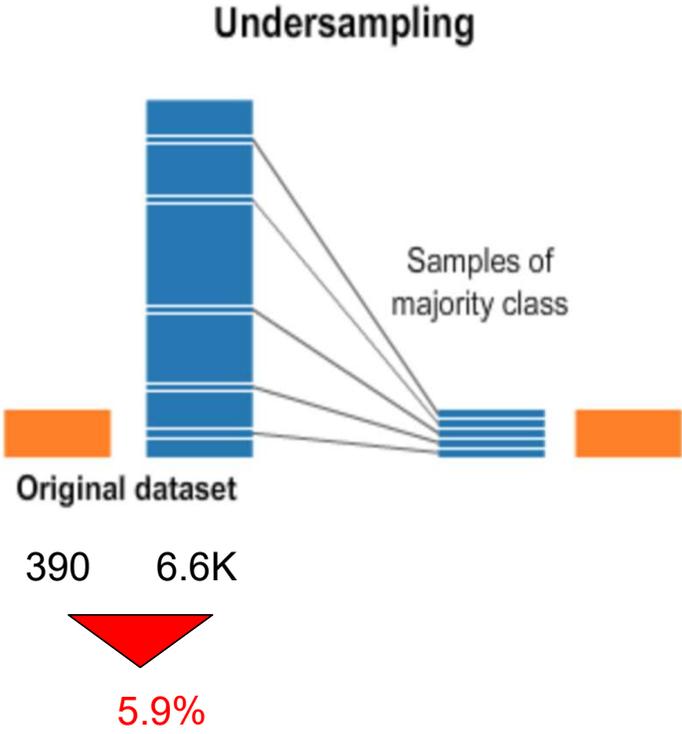
Final Deliverables



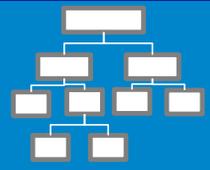
# Statistical Sampling

**Class Imbalance**

- Only 5.9% of samples out of 6.6K Disconnect Switches represent Failures
- Needed to employ statistical sampling technique
- Down-sampling which takes random samples from the majority class
  - Majority Class: Disconnect Switches in-service
  - Minority Class: Failed Disconnect Switches



# Final Model: XG Boost Predictions



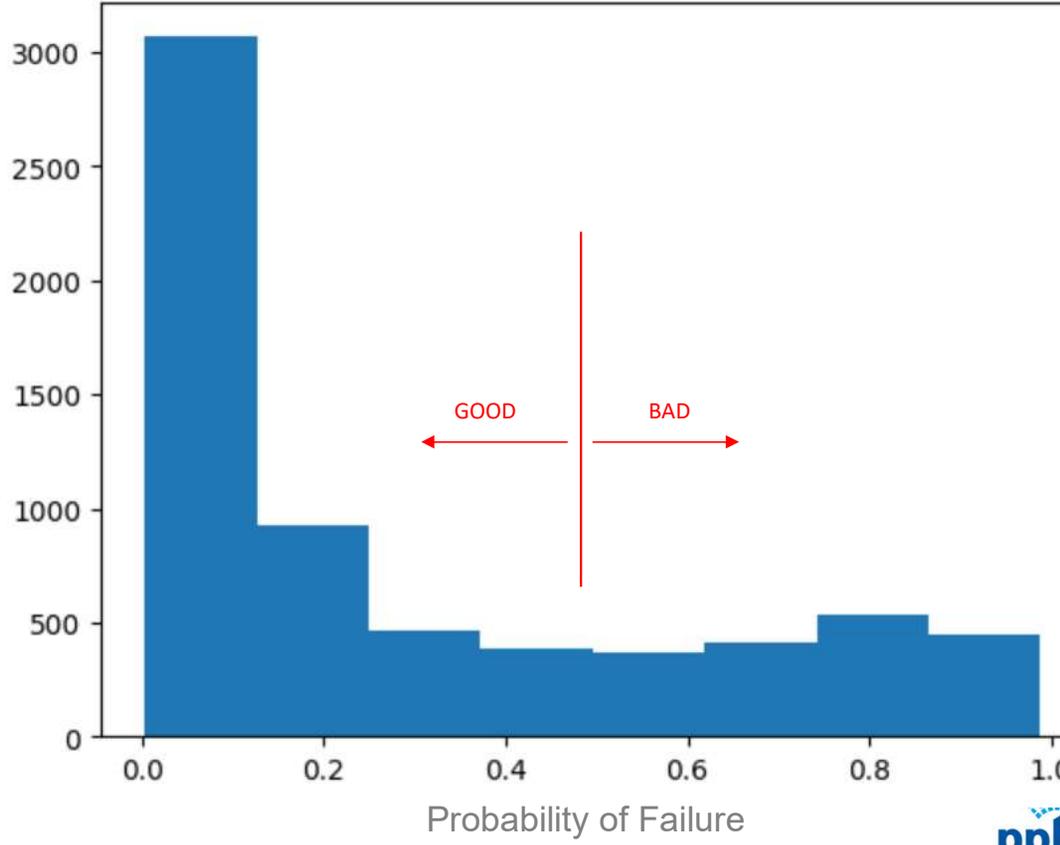
## XG Boost Classifier:

- Ensemble of weak prediction models
- Decision Tree Model

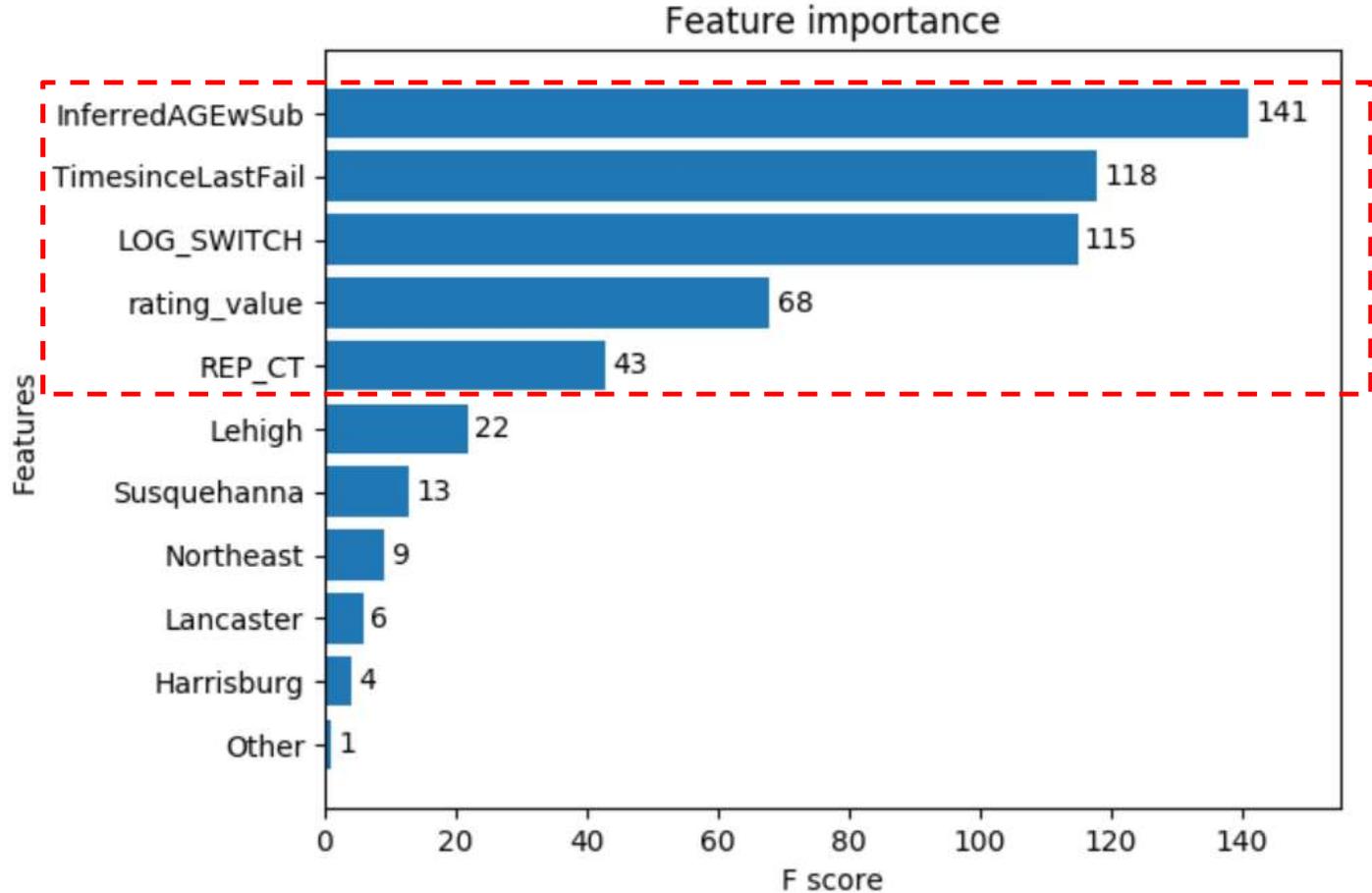
## Probability Model:

$$1 = P_{(Bad)} + P_{(Good)}$$

XGBOOST PoF



# Feature Importance



- Model driven by:
- Age
  - Time Since Last Fail
  - Switching Moves
  - Rating Value
  - Repair Count

# Model Summary

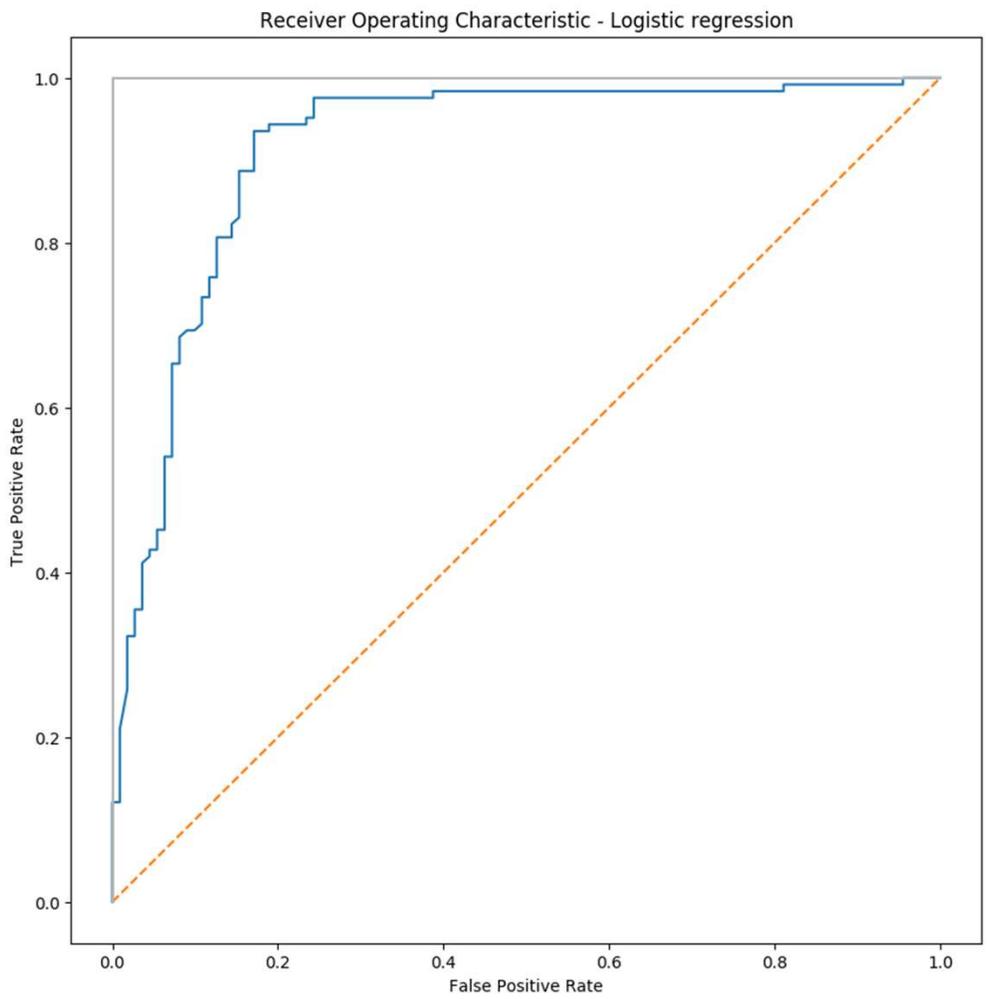


Precision - ratio of true positives to the sum of true and false positives

Recall - percent was classified correctly

f1 score - weighted harmonic mean of precision and recall such that the best score is 1.0 and the worst is 0

# Model Summary



AUC of 0.81

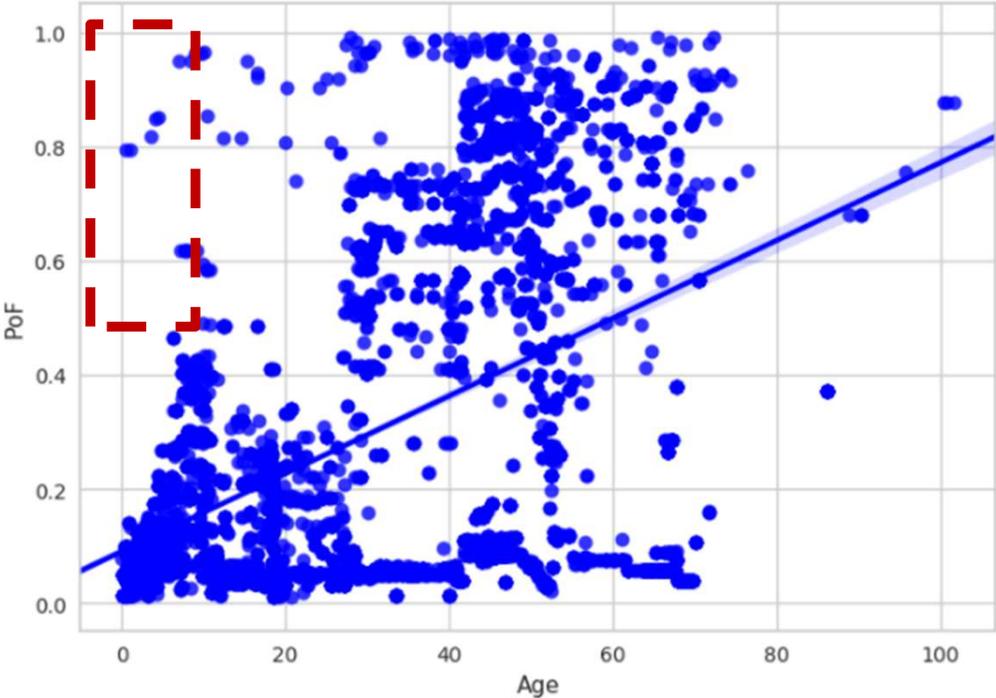


AUC: Area under the curve  
0.90 – 1.00 = excellent (A)  
0.80 – 0.90 = good (B)  
0.70 – 0.80 = fair (C)  
0.60 – 0.70 = poor (D)  
0.50 – 0.60 = fail (F)

# Final Model (XGBoost) Probability of Failure

## Targeted Approach to Identify High-Risk Units

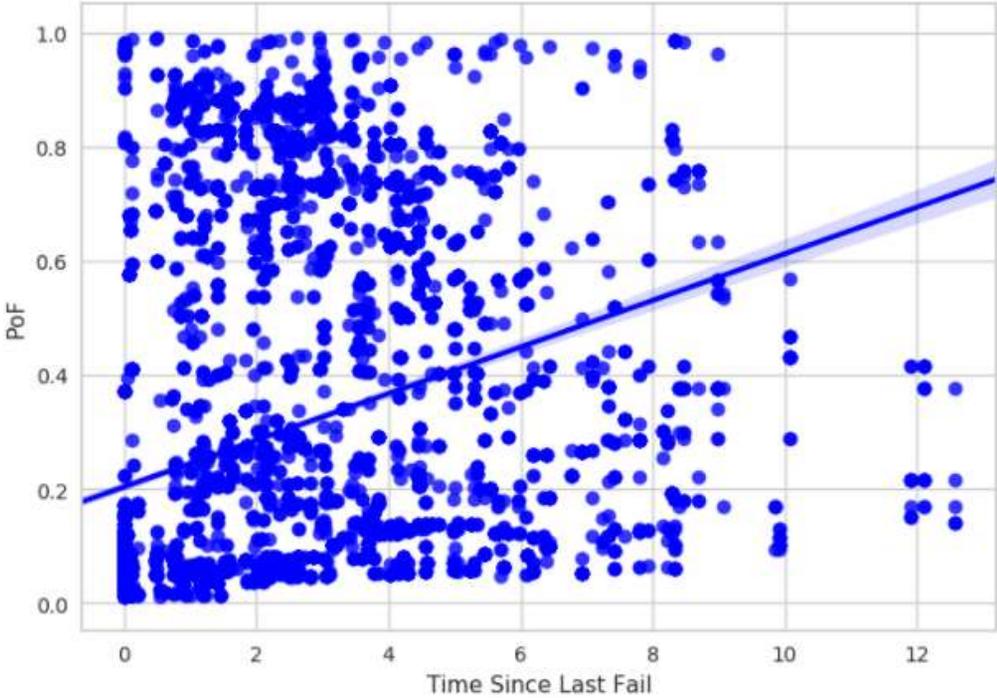
There is a few equipment that have a high PoF at young age due to having similar data points in that are actual failures at young age



# Final Model (XGBoost) Probability of Failure

## Targeted Approach to Identify High-Risk Units

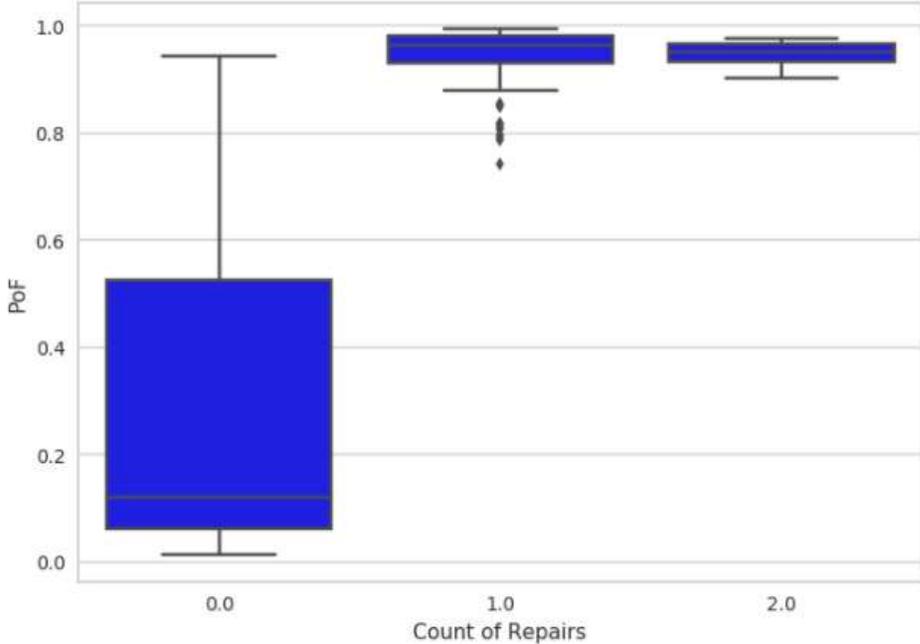
The relationship between the probability of failure and the time passed since the last failure is positive. Meaning that the longer the time since the last failure, the higher the PoF score.



# Final Model (XGBoost) Probability of Failure

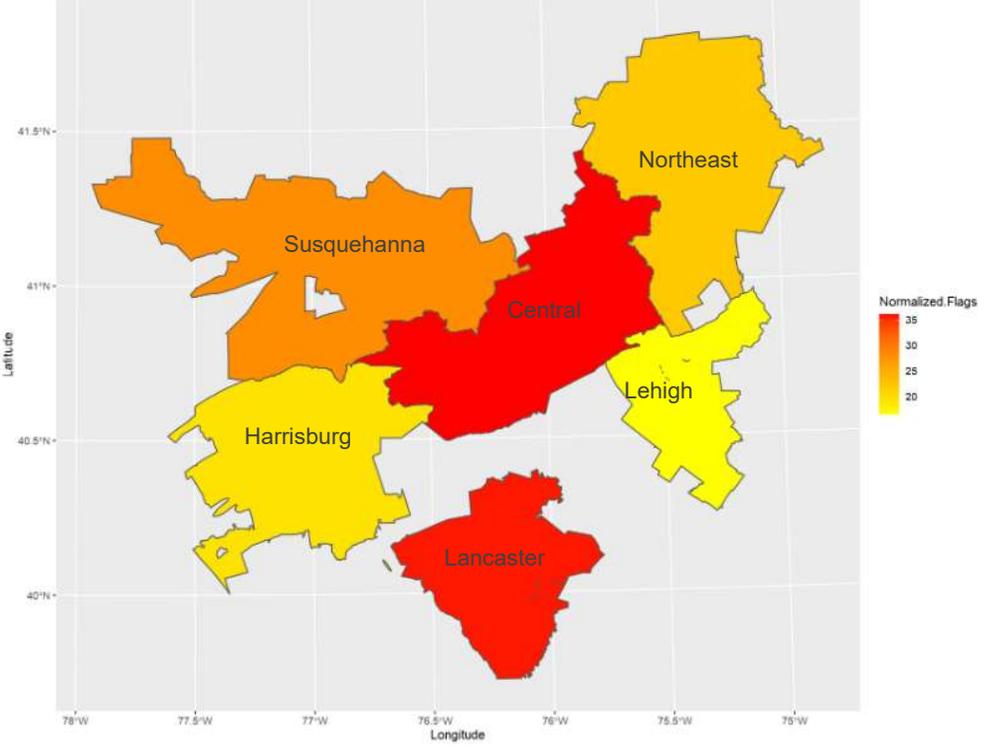
## Targeted Approach to Identify High-Risk Units

The higher the count of repairs for the LBD, the higher PoF score.



# PoF by Region

Projected Failures by Region (Normalized by count per region)



Higher density of failures experienced in Lancaster and Central

# Disconnect Switches Dashboard

LBD  No  Yes

Region: All

Substation: All

Position: All

PPL Cat. No.: All

Model: All Rating...: All

Business: All

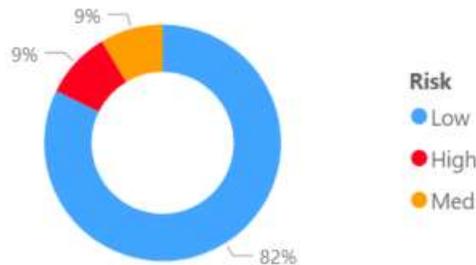
Stranded Load: All

Voltage Class: All

PoF Score: 0.01 0.97

Age: 0.07 101.84

Asset Count by Risk Level

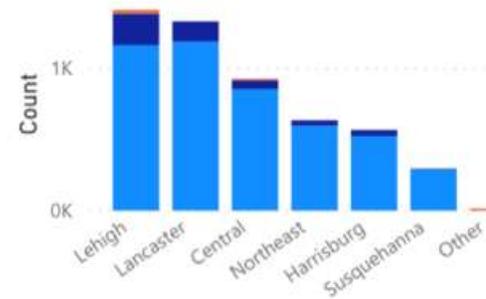


469

WO Count

Assets by Region

Business DS TS Unknown

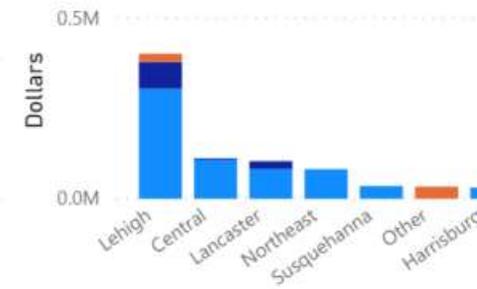


799.86K

Dollars

O&M by Region

Business DS TS Unknown



5180

Equipment Count

Substation	Position	Region	OEM	Age	WO Count	LBD	PoF Score	Model	Region	Category
MACK 69/12 KV	Transformer 1 Oper Bus Disc 12KV 3 Ph	Lehigh	S&C Electric	30.00	1	No	0.97	ALDUTI-RUPTER		145
MACK 69/12 KV	67-2 Insp Bus Disc 12KV 3 Ph	Lehigh	Royal Electric	29.99	2	No	0.97	BT		145
CATASAUQUA 138/12 KV	Oper Bus 1-2 Sect 1 Disc 12KV 3 Ph	Lehigh	Royal Electric	57.82	1	No	0.97	BT		145
ALTAMONT 69/12KV	25-4 12KV LINE DISC	Central	Royal Electric	41.67	1	No	0.97	BT		145
HARWOOD 69/12 KV	HARW-HUMB #1 66KV INSP BUS DISC	Central	General Electric	62.40	3	No	0.95	FA		146
CANADENSIS 69/12 KV	85-2 INSP BUS DISC 12KV 3PH	Northeast	Other	45.27	1	No	0.95			
PROVIDENCE 69/12 KV	OPERATING BUS SECT #1 DISC	Northeast	S&C Electric	24.30	1	No	0.95			145
QUARRYVILLE 69/12 KV	56-3 INSP BUS DISC 3 PH	Lancaster	Other	53.67	0	No	0.94			145
<b>Total</b>					<b>469</b>					

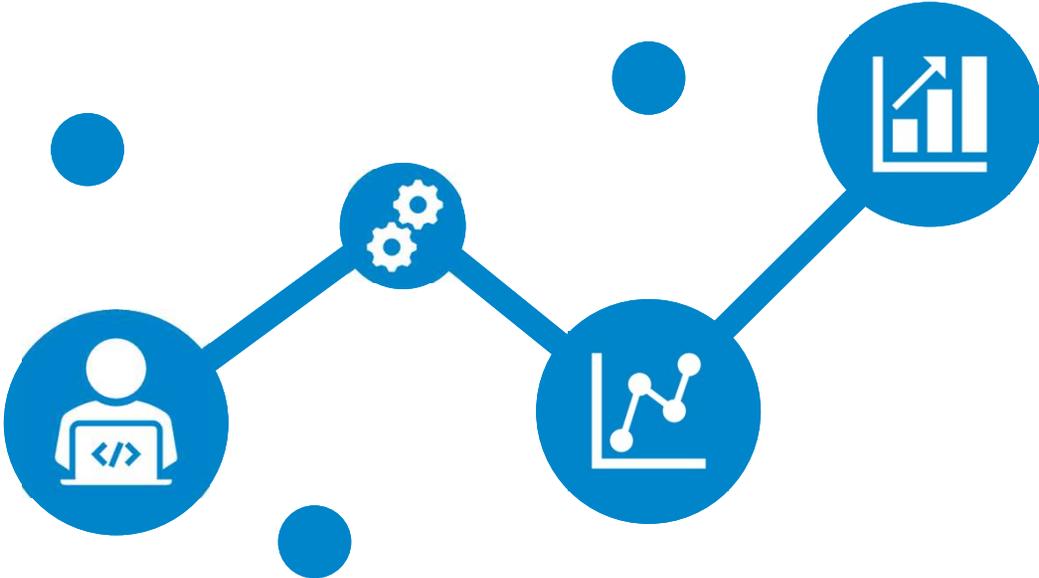
# Thanks for your support

Please contact us with any questions.

T&S Data Analytics

Neveen Omran: 610-774-4529

Juan Vazquez: 610-774-5337



# Appendix

# Disconnect Switches EDA

## Work Orders & Inventory

6589

EQUIP\_ID

390

Failure

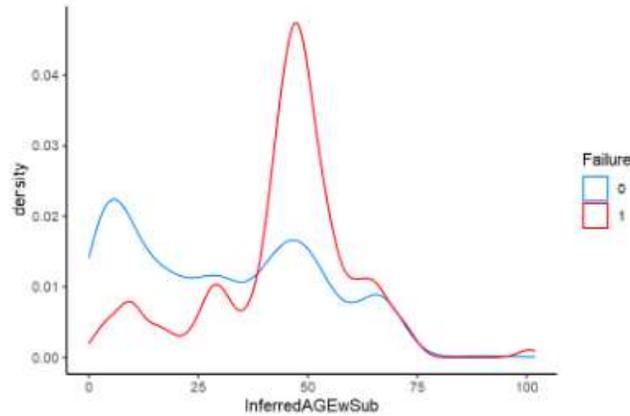
29

Manufacturer

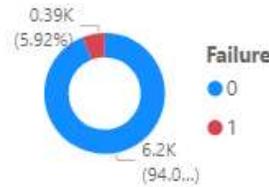


Model: All  
 Location: All  
 Manufactu...: All  
 PPL Cat #: All  
 Status: All  
 Region: All  
 Rating: All  
 POSITION: All

Failure and Age

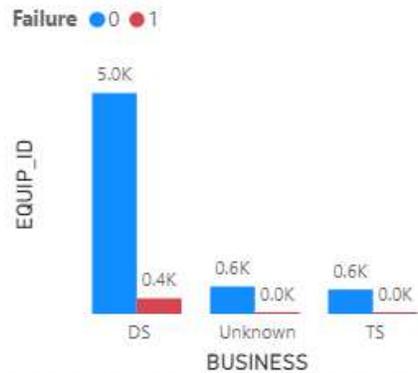


Counts of Failures

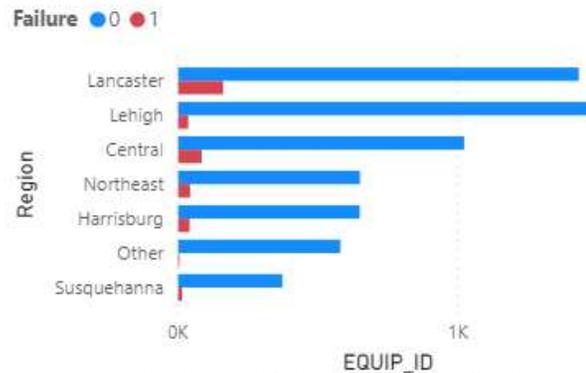


Region	Count of Equipments	Count Failures	Dollars Spent on WO
Lancaster	1592	162	774,437.50
Central	1106	85	361,550.00
Northeast	694	44	231,125.00
Harrisburg	691	42	250,968.75
Lehigh	1533	37	639,262.50
Susquehanna	388	15	226,975.00
Other	585	5	35,700.00
<b>Total</b>	<b>6589</b>	<b>390</b>	<b>2,520,018.75</b>

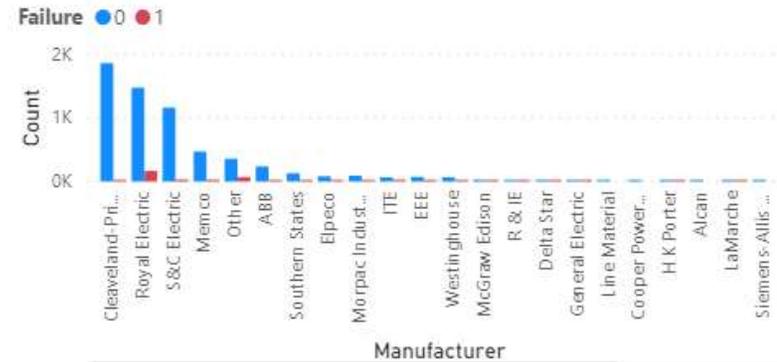
Count of Failures by Business



Failures per Region



Manufacturers



Division 2-44

Request:

In his testimony, Mr. Sorgi states (at 9:10-12) a belief that “infrastructure investments and a more localized operation model under PPL’s ownership will create jobs and support economic development in Rhode Island.” Please:

- a. Explain how PPL’s operation would be more localized than National Grid, and
- b. Provide quantifiable support on how PPL’s more localized operation model creates jobs and supports economic development.

Response:

- a. PPL and PPL RI refer to their response to data request Division 1-54.
- b. PPL and PPL RI refer to their response to data request Division 1-54.

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Division 2-45

Request:

Please provide a detailed list of the combination of best practices that will benefit the customers and the State as described in Mr. Dudkin's testimony (at 5:18-19).

Response:

As both National Grid and PPL develop an orderly transition plan, the process includes detailed deep dives into the functions needed to stand up the business starting on day 1 after closing, including the provision of certain services and functions by National Grid USA Service Company, Inc. under a Transition Service Agreements ("TSA"). This information sharing provides insight into the practices of both companies and continued learnings by both companies. Some of the areas discussed include but are not limited to advanced meter operations, smart grid technology, standards development and design criteria, use of data analytics, integrating DER, energy efficiency programs, customer experience strategy, public and employee safety programs, storm response, non-wire alternatives, traveling wave technology, vegetation management, interconnection process. The utility industry has a long history of sharing best practices. Both PPL and National Grid are involved in industry groups, including but not limited to Electric Power Research Institute, Association of Edison Illuminating Companies, Mutual Assistance organizations, Edison Electric Institute, and the WIRES Group. These discussions continue to progress and the sharing of best practices is expected to continue post close.

Division 2-46

Request:

Referencing to Mr. Dudkin's testimony (at 33:4-6), please provide a copy of all Documents delineating those aspects of the National Grid advanced metering and grid modernization plans that: (a) will integrate with the existing PPL systems; and (b) require adjustment.

Response:

At this time PPL and PPL RI (collectively "PPL") are focusing on the technology and organizational requirements needed to safely transition ownership of The Narragansett Electric Company ("Narragansett") with minimal impact to customers. PPL has reviewed the AMF Business Case and the Grid Modernization Plan that Narragansett filed with the Rhode Island Public Utilities Commission (the "Commission") and has a high-level understanding of the proposals set forth in those plans, but it has not yet undertaken a detailed review to determine the adjustments and/or modifications PPL will make to best serve Narragansett's customers. PPL has a strong record of integrating best-in-class technology into utility operations to deliver top decile electric reliability performance. PPL intends to utilize those learnings to determine the best approaches going forward as appropriate.

PPL will continue to analyze Narragansett's grid modernization plan and advanced metering proposal as this regulatory approval process for PPL RI's purchase of Narragansett proceeds, and it will supplement this response as appropriate. PPL expects to work with the Division of Public Utilities and Carriers and other stakeholders to have Narragansett prepare and file updated advanced metering and grid modernization plans after closing.

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Division 2-47

Request:

In his testimony, Mr. Sorgi mentions (at 8:15-16, 8:20) PPL's knowledge and experience implementing smart grid technology and in automating electricity networks. Please provide a detailed description of PPL's experience with smart grid technology and automation, including: the type of smart grid technology or automation, the year implemented, and the specific utility system on which it was implemented.

Response:

Please see PPL and PPL RI's response to date request Division 2-8.

The following is a list of smart grid technologies implemented by PPL Electric Utilities Corporation:

Technology	Implementation
Smart Grid - Distribution smart devices	2013-ongoing
Smart Grid - FLISR	2015-2016
Smart Grid - MOLBABs	2014-2021
Smart Grid - Transmission reclosers	2021-ongoing
Sensors - Equipment monitors	2015-ongoing
Sensors - Microprocessor relays	2012-ongoing
Sensors - 2nd generation advanced meters	2015-2019
Sensors - Dynamic line ratings	2020-ongoing

The following is a list of recent smart grid technologies implemented by Louisville Gas and Electric Company and Kentucky Utilities Company:

Technology	Implementation
Advanced Metering Systems (AMS) Opt in DSM	2014-current
Distribution Automation	2017-2021

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Electro-Mechanical Relay Replacement	2019-ongoing
SCADA Voltage Controller Upgrades	2020-ongoing
SCADA Expansion	2018-ongoing
Transmission Control Houses-Proactive Repl	2017-ongoing
Transmission Relay Panels-Proactive Repl	2017-ongoing
Transmission Remote Terminal Units-Proactive Repl	2017-ongoing
Transmission Switch - Auto	2016-ongoing
Transmission Switch - Motor Operated	2016-ongoing

Division 2-48

Request:

Please explain in detail how PPL has used its smart grid technology to streamline the process of gathering data as discussed on page 14, lines 6-10 of Mr. Dudkin's testimony.

Response:

Through PPL Electric Utilities' ("PPL Electric") incorporation of telemetered distribution devices and AMI data into its main operational systems, including its Advanced Distribution Management System ("ADMS"), PPL better understands how distributed energy resource ("DER") assets can reduce customer reliability and power quality without effective management. PPL has both the breadth and depth of experience in telemetered device and supervisory control and data acquisition ("SCADA") data, and automated power flow which uniquely positions PPL to understand how DER will impact the distribution system in real time and adjust to maximize safety and reliability accordingly.

With the data provided through telemetered devices and other smart grid technology, PPL has significant experience in real-time power flow studies and fully understands and appreciates the impact of DER on the distribution system as well as the possible advantages to leveraging smart inverter capabilities to impact the distribution grid.

For example, when a fault occurs on the distribution system, nearby DER are designed to trip offline in response. When service is restored, the DERs generally have a reconnect time delay of a few minutes before they resume generating power. During that delay, the load normally served by the DER must now be served by PPL Electric until the DER resumes generating power. With a fully deployed and self-healing fault location isolation and service restoration ("FLISR"), it became apparent that, without real-time monitoring of DER, PPL Electric cannot determine how much hidden load it needs to serve until the DER start generating again. By gathering data from smart grid devices regarding power flow from large generators on the transmission system and onto the distribution system to serve load, as well as understanding the actual power being generated by DER real time and exported to the distribution grid, PPL Electric can fully understand and plan for both a broad view and the local nuances of power flows to operate the system more safely and reliably.

Division 2-49

Request:

Provide copies of all Documents demonstrating the customer benefits associated with the 7,000 smart devices which have been installed on the transmission and distribution networks as described in Mr. Dudkin's testimony (at 10:1-3).

Response:

Counsel for PPL, PPL RI, National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL Rhode Island, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL Rhode Island, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL Rhode Island have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

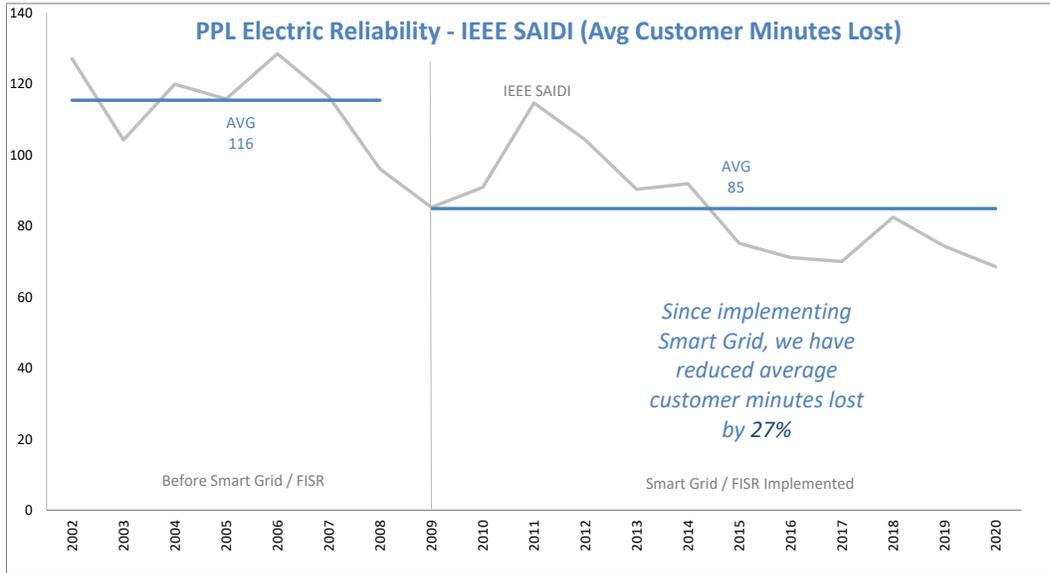
PPL Electric Utilities Corporation has installed over 7,000 smart devices on the electric transmission and distribution networks. This includes more than 4,500 smart switches and 2,000 smart capacitors on the distribution system, and nearly 1,000 smart switches on the transmission system. These switches are controlled remotely by the Transmission and Distribution System Operators, respectively. In the event of an outage, these smart switches immediately identify the fault location, isolate the fault, and restore service to customers in seconds or minutes. By comparison, manual switches require mobilization of field personnel to manually operate each switch used to isolate the fault and restore service, taking anywhere from 30 minutes to 2 hours for customer restoration.

Customer benefits are outlined in Attachment PPL-DIV 2-49-1, which is a spreadsheet showing System Average Interruption Duration Index, or SAIDI prior to and after implementation of Smart Grid. SAIDI is an IEEE 1366 method for measuring the total number of minutes an average customer experiences in a year. PPL and PPL RI also refer to their response to Division 1-35 for a description of additional customer benefits. As shown in the graph below and in Attachment PPL-DIV 2-49-1, PPL has seen an overall reduction in customer minutes lost by 27%.

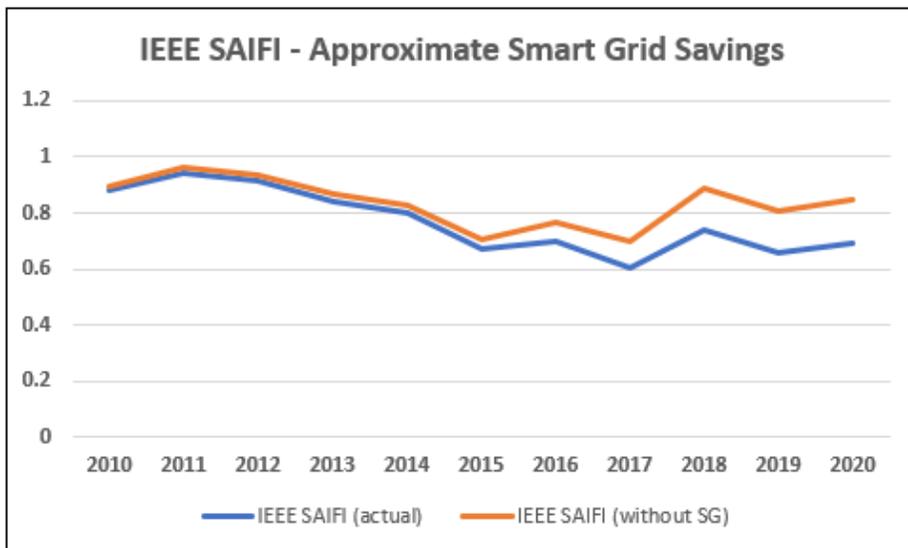
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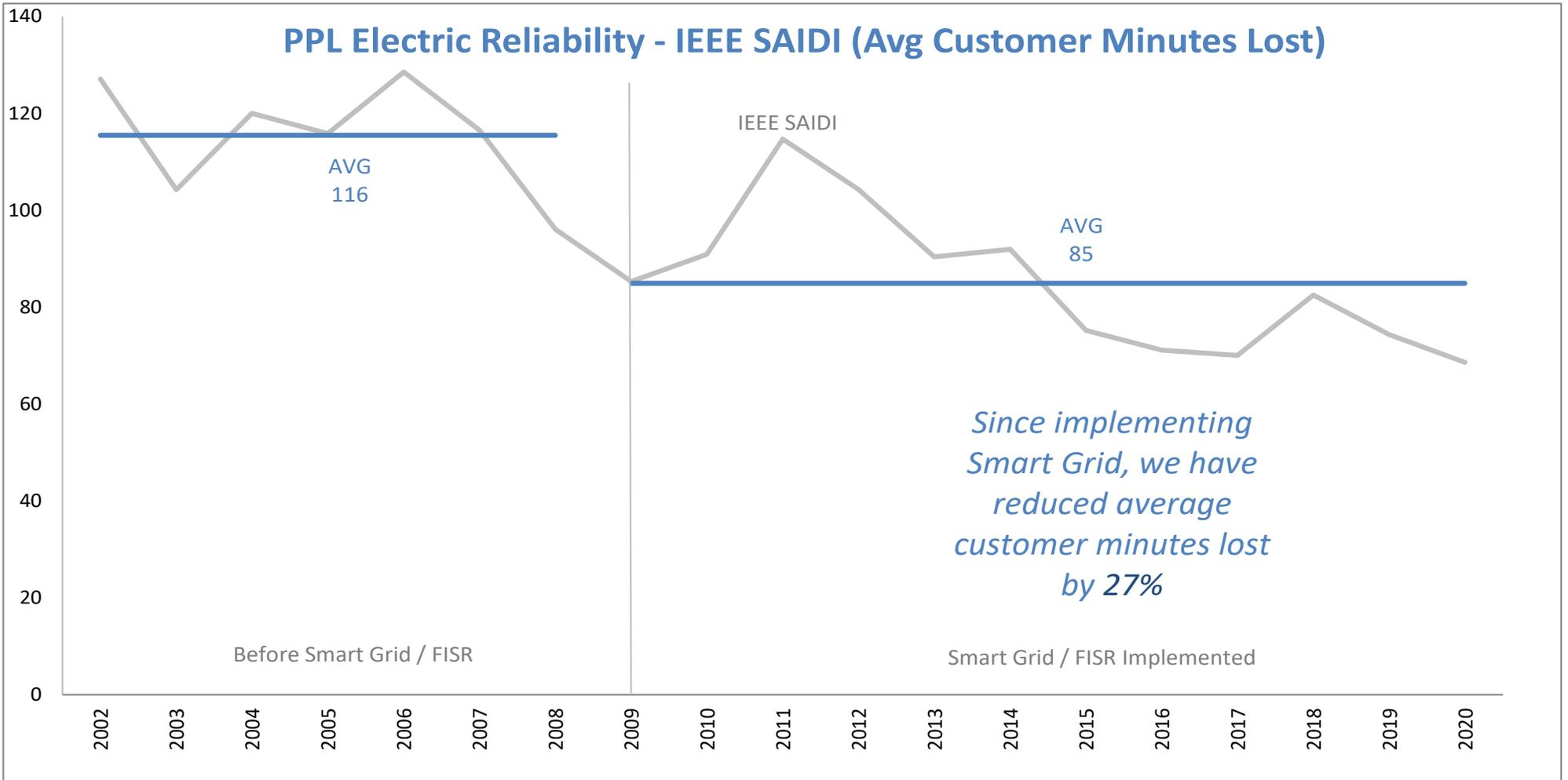
In terms of System Average Interruption Frequency Index, or SAIFI, which is an IEEE 1366 method for measuring the total number of interruptions an average customer experiences in a year, PPL has saved 1.1 million customer interruptions since the implementation of Smart Grid. The graph below and in Attachment PPL-DIV 2-49-1 shows the approximate SAIFI savings through the end of 2020.

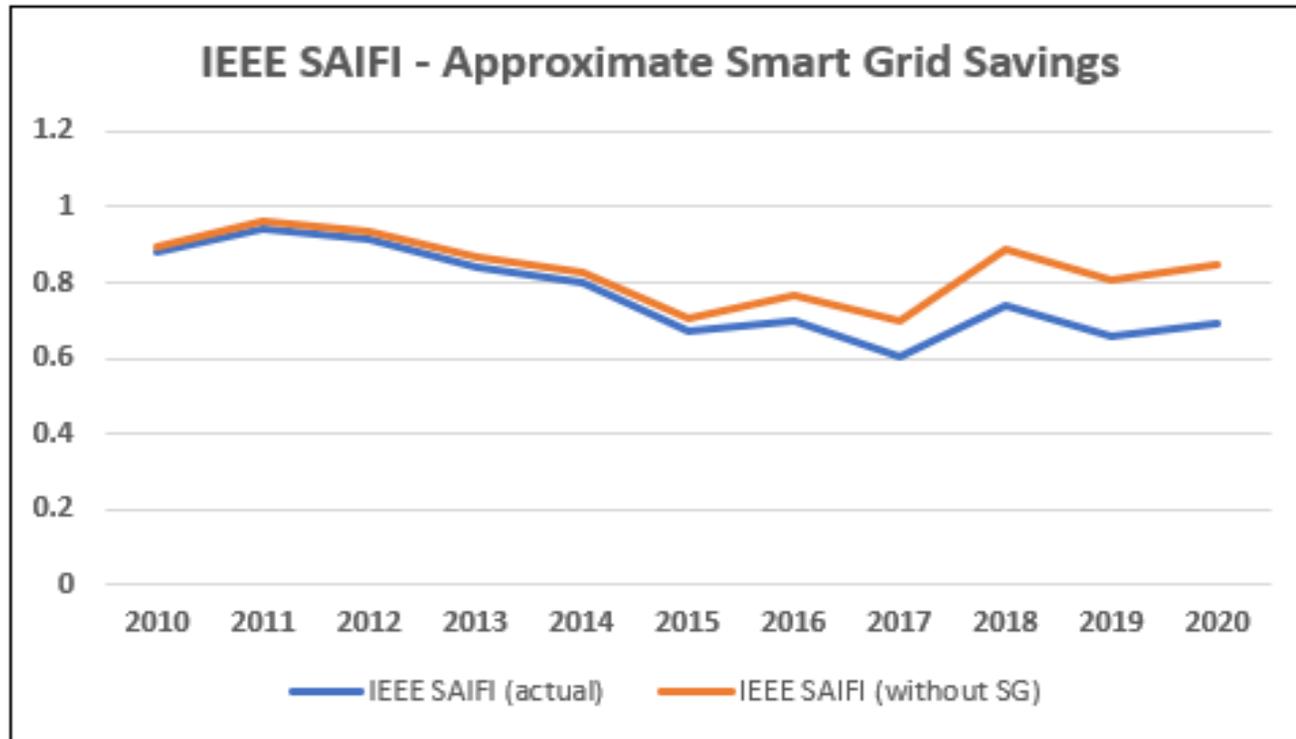


0.5 to 5 minutes CI, D-OH only, multi-phase only.

Year	CI Saved	CMI saved based on average PUC CAIDI
2010	25,446	3,613,332
2011	30,471	4,326,882
2012	36,934	5,244,628
2013	34,712	4,929,104
2014	43,631	6,195,602
2015	48,252	6,851,784
2016	95,345	13,538,990
2017	130,028	18,463,976
2018	218,530	31,031,260
2019	213,322	30,291,724
2020	228,563	32,455,946
2021	106,399	15,108,658
	1,211,633	172,051,886

Business Use





Division 2-50

Request:

On page 10, lines 5-7 of Mr. Dudkin's testimony, he indicates that PPL avoided its one millionth customer outage because of smart grid technology. Please explain how PPL determined that smart grid technology was responsible for avoiding the outages.

Response:

The smart grid technology that Mr. Dudkin refers to consists of two components: smart field devices (SCADA-controlled breakers, reclosers, and switches), and a software commonly referred to in the utility industry as FLISR (Fault Location, Isolation, and Service Restoration). PPL Electric Utilities' ("PPL Electric") FLISR implementation consists of an application that interfaces with its ADMS system. When an outage occurs, the smart field devices report fault indication and other telemetry to ADMS. FLISR uses that information to identify the trouble location and isolates it using the nearest smart field devices. FLISR then re-configures the electric distribution system using additional smart field devices to restore power outside of the trouble location. The result is that only the customers nearest to the trouble location experience a "permanent" outage (over 5 minutes). Other customers impacted experience only a "momentary" interruption, which is not considered a permanent customer outage under Pennsylvania law. Without the use of smart grid technology, all customers impacted would experience a permanent customer outage.

In addition to isolating the trouble location and restoring power outside of the trouble location, FLISR also provides a log of its actions and number of customers restored through its re-configurations. PPL Electric operations personnel review this log daily and keep a running count of all customers that have avoided a permanent customer outage. A review of this count identified that smart grid technology – FLISR and smart field devices - had prevented more than one million permanent customer outages as of the end of 2020.

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Division 2-51

Request:

Please provide all Documents, including analyses and plans, that address the possible installation on the Narragansett system of smart grid and automation devices.

Response:

At this time PPL has not performed an analysis of the specific smart grid and automation devices that it plans to install on the Narragansett system, nor has it developed any plans for such installation. As set forth in the PPL and PPL RI's responses to data requests Division 1-35 and Division 2-47 through Division 2-50, PPL Electric Utilities Corporation ("PPL Electric") has significant experience in the utilization of smart grid and automation devices, and PPL plans to rely on that experience in ultimately determining the best systems to install on the Narragansett electric system.

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Division 2-52

Request:

For the \$112 million of the LG&E and KU multi-year initiative discussed on page 10, lines 7-16 of Mr. Dudkin's testimony:

- a. Provide a breakdown of the referenced \$112 million expenditures by spending category;
- b. Explain how these smart grid investments allow PPL utilities to immediately pinpoint the location of power outages;
- c. State whether the technology implemented at each PPL utility system is identical, and if not, explain the differences;
- d. State whether all the smart grid technologies and Advanced Distribution Management Systems are managed through a single service within PPL. If they are not, explain how they are managed.

Response:

a. See the table below showing Louisville Gas & Electric and Kentucky Utilities' ("LGE-KU") actual expenditures from 2017 through May 2021. The Advanced Distribution Management System ("ADMS") project will be complete by the end of December 2021, one year early, with an estimated full project spend under \$112 million.

Expense Category	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	Jan - May 2021 Actuals	Total
Labor	\$ 1,100,516	\$ 3,501,453	\$ 3,385,217	\$ 2,262,954	\$ 588,204	\$ 10,838,344
Outside Services	\$ 3,408,330	\$ 6,834,372	\$ 10,392,077	\$ 6,433,183	\$ 1,342,010	\$ 28,409,972
Materials	\$ 4,370,369	\$ 14,915,403	\$ 16,072,779	\$ 10,754,985	\$ 2,337,499	\$ 48,451,035
Other	\$ 1,836,545	\$ 3,243,437	\$ 3,256,594	\$ 3,006,537	\$ 620,704	\$ 11,963,817
<b>Total</b>	<b>\$ 10,715,760</b>	<b>\$ 28,494,664</b>	<b>\$ 33,106,668</b>	<b>\$ 22,457,658</b>	<b>\$ 4,888,417</b>	<b>\$ 99,663,167</b>

b. When an outage occurs on the distribution system, an electronic recloser detects the fault and communicates fault data over cellular communications to the Distribution Supervisory Control and Data Acquisition ("DSCADA") system. The DSCADA will in turn pass this information to the ADMS which subsequently calculates the fault location and displays in the Network Management System for system operators and field personnel to use.

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c. LGE-KU's ADMS is a different set of systems which consist of an Oracle/OSI ("Open Systems International") based solution that integrates with LGE-KU's Oracle Outage Management System and OSI Energy Management System. PPL Electric Utilities Corporation ("PPL Electric") uses ADMS from General Electric's suite of products, Eterra-Distribution. PPL Electric uses Eterra-Distribution because it provides compatibility benefits with its energy management system and transmission management system.

d. LGE-KU and PPL Electric each manage and support their own ADMS. LGE-KU and PPL Electric are served by separate service companies and rely on separate grid management systems. It is anticipated that PPL Electric and PPL Rhode Island will be more closely aligned and jointly use systems and technologies where it is economical and feasible.

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Division 2-53

Request:

Provide a list of each of the specific industry-leading advances in integrating DER made by PPL and referenced on page 13, lines 17-18 of Mr. Dudkin's testimony.

Response:

PPL and PPL RI refer to their responses to data requests Division 1-35 and 2-14f.

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Division 2-54

Request:

Please provide a copy of each of the PPL distributed energy resource interconnection tariffs approved by each commission in the PPL jurisdictions.

Response:

Please see the following attachments:

Attachment PPL-DIV 2-54-1 (PPL Electric Utilities Corporation's ("PPL Electric") General Tariff – Rule 11 and Rule 12)

Attachment PPL-DIV 2-54-2 (Louisville Gas & Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), and Old Dominion Power Company's ("ODP") Net Metering Service Tariff)

Attachment PPL-DIV 2-54-3 (LG&E, KU, and ODP's Small Capacity Cogeneration and Small Power Production Qualifying Facilities Tariff)

Attachment PPL-DIV 2-54-4 (LG&E, and KU's Large Capacity Cogeneration and Small Power Production Qualifying Facilities Tariff)

Interconnections for generators participating in the PJM wholesale market are subject to the PJM Governing Documents, which can be found at the following link:

<https://pjm.com/library/governing-documents>

Division 2-55

Request:

For each PPL regulated utility, please provide the following data, as of May 30, 2021:

- a. Number and capacity of distribution-interconnected DER by fuel type; and
- b. The outstanding interconnection queue.

Response:

- a. Please see Attachment PPL-DIV 2-55-1, which is PPL Electric Utilities Corporation's ("PPL Electric") May 2021 Monthly Electric Power Industry Report showing PPL Electric's total net metered interconnections.

PPL Electric has 5 MW of interconnected solar generation which does not participate in net metering.

As of May 30, 2021, Louisville Gas & Electric ("LG&E") and Kentucky Utilities ("KU") had the following distribution-interconnected DER.

Energy Type	Customers	Connected kW
Solar	1,589	18,845
Wind	9	23
Hydro	1	50
Storage	44	354
Total DER (Excluding Storage)	1,603	18,918

- b. As of May 31, 2021, PPL Electric has 717 system-wide projects that are in the interconnection queue, totaling 21,079 kW in nameplate capacity.

As of May 30, 2021, LG&E and KU had 5 interconnection applications that were received by the Companies but were awaiting approval pending an interconnection engineering review. A total of 263 applications were approved but are either waiting on customer installation completion or meter installation.

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These numbers are fluid and change daily based on applications received, cancellations, meter installations, and customer installation progress.

**FORM EIA-861M**  
**MONTHLY ELECTRIC POWER INDUSTRY REPORT**

OMB No. 1905-0129  
 Approval Expires: 3/31/2020  
 Burden Hours: 1.37

Entity Name: \_\_\_\_\_ May  
 Entity ID: \_\_\_\_\_ Data Year: 2021

**SCHEDULE 3. PART A. NET METERING PROGRAMS**

Provide the information about programs by State, balancing authority, customer class, and technology for all net metering applications.

State	PA	Nature of Reported Data				
		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Photovoltaic	Net Metering Installed Capacity (MW)	96.292	85.200	12.899		194.391
	Net Metering Installations	11,299	751	51		12,101
	Storage Installed Capacity (MW)					0.000
	Storage Installations					0
	Virtual NM Installed Capacity (1 MW and greater)		5.575			5.575
	Virtual NM Customers (1 MW and greater)		4			4
	Virtual NM Installed Capacity (less than 1MW)	0.938	6.961			7.898
	Virtual NM Customers (less than 1MW)	39	117			156
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0
Wind	Net Metering Installed Capacity (MW)	0.313	0.129			0.442
	Net Metering Installations	97	20			117
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0
Other	Net Metering Installed Capacity (MW)	0.143	32.445	2.429		35.017
	Net Metering Installations	8	36	2		46
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0
Total	Net Metering Installed Capacity (MW)	96.748	117.774	15.328	0.000	229.850
	Net Metering Installations	11,404	807	53	0	12,264
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0	0	0	0	0
Grand Total	Net Metering Installed Capacity (MW)	97.686	130.310	15.328	0.000	243.323
	Net Metering Installations	11,443	928	53	0	12,424
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0	0	0	0	0

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Division 2-56

Request:

Provide a copy of any cybersecurity governance plans utilized by PPL or its affiliates in its interconnection processes for DERs.

Response:

PPL Corporation's enterprise security standard regarding third party cybersecurity risk management applies to all entities and affiliates of PPL Corporation and its domestic and international subsidiaries (collectively, Company). This standard outlines the minimum expectations for management of all current and prospective vendors, service providers, or contractors that have direct or remote electronic access to Company digital systems or data, or that provide programmable products (*i.e.*, software or hardware), or services used in the Company's Information Technology, Industrial Control System, or Operational Technology environments. PPL and PPL RI refer to Attachment PPL-DIV 2-56-1, Third Party Cybersecurity Risk Management (ESS-07).

PPL Electric Utilities Corporation's Cyber Security Supply Chain Risk Management Plan addresses all acquisitions, including non-contractual procurement, and digital or electronic sharing of Confidential or higher classified information without a contract. PPL and PPL RI refer to Attachment PPL-DIV 2-56-2, EU-NERC-CIP-013, PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan.

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**Third Party Cybersecurity Risk  
Management**

*Effective Date:*  
**07/01/2021**

*Version:*  
**4**



## Third Party Cybersecurity Risk Management (ESS-07)

### 1. Overview

This Enterprise Security Standard (“Standard”) addresses the minimum requirements for managing third party cybersecurity risks. Recognizing both the value and cybersecurity risks associated with engaging outside companies for various products and services, this Standard is a method of mitigating the risks to realize maximum value for the corporation.

### 2. Scope

This Standard applies to all entities and affiliates of PPL Corporation and its domestic and international subsidiaries (collectively, the “Company”).

This Standard outlines the minimum expectations for management of all current and prospective vendors, service providers, or contractors (collectively, “third parties”) that have direct or remote electronic access to Company digital systems or data, or that provide programmable products (i.e. – software or hardware), or services used in the Company’s Information Technology (IT), Industrial Control System (ICS), or Operational Technology (OT) environments.

Certain aspects of the Company’s operations are subject to mandatory requirements and regulations and the Company has developed programs to address compliance with and administration of these requirements. This Standard is not intended to supersede or contradict existing controls or programs in place to meet industry mandated requirements or regulations but the Company intends to integrate this Standard into existing programs where appropriate. Should this Standard conflict with or negatively impact the Company’s ability to comply with mandatory requirements and regulations, the controls and programs developed to address the mandatory requirements and regulations shall take precedence.

This Standard may be changed at any time at the Company’s discretion.

### 3. Responsibility

PPL Enterprise Security is responsible for maintaining this Standard and providing guidance to adhere to the requirements. Leadership of entities and affiliates of PPL Corporation and its domestic and international subsidiaries are accountable for implementing the requirements in this Standard, through entity specific policies and procedures.

### 4. Management of Third Parties

#### Screen Third Parties

Repeatable processes shall be established and implemented to screen (or update the screening of) third parties upon commencement of the procurement process or initiation of a relationship with a third party for products or services used in IT, ICS, or OT environments. If the third party meets the criteria outlined in the Scope section above, gather additional information from the third party to assist with risk determination.

#### Maintain a List of Third Parties

An inventory of third parties within the scope of this Standard shall be maintained. This inventory may be stored in any system or format and be in sufficient detail to meet operational needs as established by the Subsidiary.

Inventory shall be completed for all third parties by December 31, 2021.

#### Maintain a Deny List

Develop and maintain a process to implement a “deny list” of third parties, components, services, or products that may not be utilized, in whole or in part. This process should be able to accept additions to the deny list from various sources including the government, Enterprise Security, or business leaders within the organization. Subsidiaries shall consult this list prior to signing any contracts. Use of any third party on this list must receive approval from the Corporate Security Council (CSC) in addition to following the steps in Section 10, Exceptions.

Any existing contracts with third parties on the deny list shall be identified by December 31, 2021.

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## 5. Open Source Software

Develop and maintain processes that address the use of open source software or other software where the Company cannot obtain commercial support. These processes shall address both the use of open source software packages as well as open source software utilized by company developers. These third parties do not have to be assigned to a tier. The use of this software shall be included in the List of Third Parties.

These processes shall minimally address the following:

- Assess the code/software using static and dynamic code analysis
- Receive notifications of updates to the code repository/source
- Actively monitor for vulnerabilities released that impact the code/software
- Include Open Source Software in existing license management programs

## 6. Develop Cybersecurity Contract Language

Develop and maintain processes for the inclusion of preferred contract terms that address common cybersecurity concerns in contracts with third parties. Exact language may be dynamic per contract and shall consider the third party tier, classification of data, volume of data, services or products provided by the third party, and any other criteria considered important, when determining the controls that will be documented in the contract.

Preferred standard contract terms shall be developed to address at least the following:

- Technical cybersecurity controls to protect data while it's being processed or handled by a third party, including encryption
- Incident response processes, including log retention and review
- Documented notification criteria and procedures, in the event a compromise occurs
- Ownership, access, handling and restrictions on how a third party can use Company data
- Applicable requirements of other Enterprise Security Standards or subsidiary specific security policies
- The right to audit the third party to validate compliance with contract provisions
- Security of third party owned computer devices or networks that may access Company systems or networks
- Mitigations to protect Company data, information and systems

## 7. Evaluate Third Party Cybersecurity Controls

Develop and maintain a process that enables understanding of the current state of the third party's cybersecurity program, risk management program, and technical security controls. This process may occur by utilizing commercially available questionnaires (SIG Shared Assessments, ISN, KY3P, NATF, etc.), through subsidiary specific questionnaires, or through another means that the subsidiary deems appropriate. This evaluation of controls may be dynamic, asking appropriate questions of the third party based upon the tier rating, risks presented, and the type and volume of data being shared.

This evaluation of controls shall at a minimum include assessing the third party's ability to identify, protect, detect, respond, and recover from cybersecurity threats.

## Track Third Party Cybersecurity Findings

A process shall be developed and implemented to document third party findings (i.e., areas where the third party may not meet all requirements). This process shall include a ranking methodology for prioritizing the criticality of findings, target remediation timelines based on third party tier and finding criticality, and the tracking of remediation activities undertaken with or by the third party (with such remediation activities tracked to completion), internal Company controls that mitigate or obviate risk (including where third party remediation is not undertaken or is not able to meet target remediation timelines), or risk acceptance by the subsidiary.

## 8. Third Party Risk Tiers

### Develop a Tier Methodology

Develop a process that assigns a tier to each third party identified in the inventory and scopes the risk presented by the third party. The tiering process shall consider the type and volume of data the third party will interact with the product(s) or service(s) provided by the third party, and any types of technical connection or integration of third party systems or networks with Company systems or networks.

**Tier 1** shall minimally include:

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- Third parties that provide programmable hardware or software, or services utilized in ICS or OT environments that are relied upon for operations of critical systems where failure to provide the contracted product or service would likely cause a disruption to one or more critical business processes for several hours or more or where the interruption would cause a significant negative impact on subsidiary operations
- Third parties that have administrator access to ICS or OT systems that are deemed as critical for delivery of critical business operations or adherence to regulations as determined by the subsidiary

**Tier 2** shall minimally include:

- Third parties that provide programmable hardware or software, or services utilized in IT environments that are relied upon for operations of essential systems where failure to provide the contracted product or service would likely cause a disruption to one or more essential business processes for several hours or more or where the interruption would cause a significant negative impact on subsidiary operations
- Third parties that have administrator access to IT systems that are deemed essential for delivery of business operations or adherence to regulations as determined by the subsidiary
- Third parties that have electronic access, either direct or remote, to Restricted data or systems that process Restricted data, except where those services are exclusively delivered utilizing Company owned computing assets
- Third parties that provide hardware, software, or services utilized in ICS or OT environments that are relied upon for operations of systems where failure to provide the contracted product or service would likely cause a disruption to one or more important business processes for several hours or more or where the interruption would cause a meaningfully negative impact on subsidiary operations
- Third parties that have administrator access to ICS or OT systems that are deemed important for delivery of business operations as determined by the subsidiary

**Tier 3** shall minimally include:

- Higher Risk Cloud Service Providers (CSP) as defined in the Cloud Security Standard (ESS-08) that do not meet the definition of a Tier 1 or 2 provider
- Managed Service Providers (MSP) that do not meet the definition of a Tier 1 or 2 provider
- Third parties that have administrator access to ICS, or OT systems that do not meet the definition of a Tier 1 or 2 provider
- Third parties that have electronic access, either direct or remote, to Confidential data or systems that process Confidential data, except where those services are exclusively delivered utilizing Company owned and managed computing assets
- Third parties that have administrator access to IT systems not in Tier 2

**Tier 4** shall minimally include:

- Remaining CSPs
- Third parties that have electronic access, either direct or remote, to Business Use data or systems that process Business Use data
- Third parties that provide staff augmentation services where those services are exclusively delivered utilizing Company owned and managed computing assets
- All other third parties with a contract that provide hardware, software, and services utilized in Company IT, ICS, or OT, but are not in tiers 1, 2, or 3

**9. Requirements and Controls per Tier**

Develop and implement controls for each third party based upon their tier.

**Tier 1** controls are effective July 1, 2021 for all new and renewed contracts and shall minimally include:

- **Cybersecurity Monitoring:** Monitor the ongoing security posture of third parties via a commercially available cybersecurity monitoring service. Use the results provided by this service to inform subsidiary of third party specific cybersecurity risks and respond to the risks identified as the subsidiary deems appropriate. Additionally, utilize a similar service to analyze the security posture of a company prior to signing or renewing a contract
- **Insurance:** Develop a process to determine the appropriate level of cybersecurity insurance required for the third party
- **Incident Response:** Establish and maintain the ability to engage the third party to assist the subsidiary during incident response activities including maintaining contact information for security representatives
- **Incident Notification:** Third parties shall notify predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract

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- **Security Vulnerabilities:** Third parties shall either notify predefined contacts or make equivalent information publicly available in a timeframe deemed appropriate by the subsidiary of any security vulnerabilities in products or services in scope of the contract
- **Access:** Establish a process requiring notification of predefined contacts when third party representatives that have access to computer systems or data, remote or onsite, no longer require access. This process shall also address technical controls for remote access connections to subsidiary networks
- **External Security Review:** Request the third party have its security programs reviewed by an independent third party (SOC 2 type II, PCI, ISO, NATF, etc.) at a frequency determined by the subsidiary and regularly review the reports. Reports can be summaries so long as sufficient detail is available to understand the effectiveness of the cybersecurity program. If the third party charges for such a report, the subsidiary shall use its discretion to decide if the fee is reasonable given the risks posed by the third party
- **Ownership:** To the extent possible, determine ownership structure of the third party and use this information as a factor in overall risk posed by a third party. Request notification when a change in ownership occurs
- **Background Checks:** Require background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the third party or the subsidiary
- **Country of Origin:** When purchasing hardware and/or software, request the third party disclose the country or countries where hardware and/or software components are designed, manufactured, assembled, developed, or supported. Compare the countries in question to a list maintained by the subsidiary and Enterprise Security and use this information to as part of a risk informed decision to contract with the third party
- **Insider Risk:** Inquire if the third party has an insider risk program and evaluate the strength of the program
- **Privacy:** Evaluate on a per contract basis the need to implement both contractual and technical controls to protect data in accordance with entity-specific privacy policies and procedures
- **Cybersecurity in Contract:** Include appropriate cybersecurity terms within the contract
- **Evaluate Cybersecurity Controls:** Conduct a review of the cybersecurity controls in place at the third party prior to signing the contract and at an interval determined by the subsidiary, not to exceed two years or contract renewal, whichever occurs first

**Tier 2** controls are effective July 1, 2022 for all new and renewed contracts and shall minimally include:

- **Insurance:** Develop a process to determine the appropriate level of cybersecurity insurance required for the third party
- **Incident Response:** Evaluate on a per contract establishing and maintain the ability to engage the third party to assist the subsidiary during incident response activities including maintaining contact information for security representatives
- **Incident Notification:** Third parties shall notify predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract
- **Security Vulnerabilities:** Third parties shall either notify predefined contacts or make equivalent information publicly available in a timeframe deemed appropriate by the subsidiary of any security vulnerabilities in products or services in scope of the contract
- **Access:** Establish a process requiring notification of predefined contacts when third party representatives that have access to computer systems or data, remote or onsite, no longer require access. This process shall also address technical controls for remote access connections to subsidiary networks
- **External Security Review:** Evaluate on a per contract basis requesting the third party have its security programs reviewed by an independent third party (SOC 2 type II, PCI, ISO, NATF, etc.) at a frequency determined by the subsidiary and review the reports. Reports can be summaries so long as sufficient detail is available to understand the effectiveness of the cybersecurity program. If the third party charges for such a report, the Subsidiary shall use its discretion to decide if the fee is reasonable given the risks posed by the third party
- **Background Checks:** Evaluate on a per contract basis requiring background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the third party or the subsidiary
- **Country of Origin:** When purchasing hardware and/or software, request the third party disclose the country or countries where hardware and/or software components are designed, manufactured, assembled, developed, or supported. Compare the countries in question to a list maintained by the subsidiary and Enterprise Security and use this information to as part of a risk informed decision to contract with the third party
- **Insider Risk:** Evaluate on a per contract basis evaluating if the third party has an insider risk program
- **Privacy:** Evaluate on a per contract basis the need to implement both contractual and technical controls to protect data in accordance with entity-specific privacy policies and procedures
- **Cybersecurity in Contract:** Include appropriate cybersecurity terms within the contract

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- **Evaluate Cybersecurity Controls:** Conduct a review of the cybersecurity controls in place at the third party prior to signing the contract and at each contract renewal

**Tier 3** controls, effective at a date of the subsidiary's choosing, are at the discretion of the subsidiary but should minimally consider:

- **Incident Notification:** Evaluate on a per contract basis including notification of predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract
- **Background Checks:** Evaluate on a per contract basis requiring background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the third party or the subsidiary
- **Country of Origin:** Evaluate on a per contract basis, when purchasing hardware and/or software, requesting the third party disclose the country or countries where hardware and/or software components are designed, manufactured, assembled, developed, or supported. Compare the countries in question to a list maintained by the subsidiary and Enterprise Security and use this information to as part of a risk informed decision to contract with the third party
- **Cybersecurity in Contract:** Evaluate on a per contract basis whether including cybersecurity terms within the contract is necessary to manage risk
- **Evaluate Cybersecurity Controls:** Evaluate on a per contract basis conducting a review of the cybersecurity controls in place at the third party prior to signing the contract and at each contract renewal

**Tier 4** controls, effective at a date of the subsidiary's choosing, are at the discretion of the subsidiary but should minimally consider:

- **Background Checks:** Evaluate on a per contract basis requiring background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the third party or the subsidiary
- **Country of Origin:** Evaluate on a per contract basis, when purchasing hardware and/or software, requesting the third party disclose the country or countries where hardware and/or software components are designed, manufactured, assembled, developed, or supported. Compare the countries in question to a list maintained by the subsidiary and Enterprise Security and use this information to as part of a risk informed decision to contract with the third party

If individual contracts or controls fail to meet the requirements of the appropriate tier, each subsidiary shall develop a process that allows company leadership to make risk informed decisions regarding the cybersecurity posture and controls of a third party prior to signing the contract.

#### 10. Exceptions

If the requirements of this Standard cannot be met, an exception shall be documented and approved as follows:

- Exceptions and mitigating controls shall be logged.
- Exceptions are subject to approval by the subsidiary/business unit level Chief Information Officer (CIO) and Director of IT Security or equivalent.
- All approved exceptions must be validated annually.
- Exceptions will be presented and reviewed at the Subsidiary Security Councils, and trends will be reviewed at the Corporate Security Council.

#### 11. Revision History:

Standards Owner: W. Mark Brooks  
 VP & Chief Information Security Officer

Version	Issue Date	Revision Comments
1	9/29/2019	1. Third Party Cybersecurity Risk Management Standard initial draft
2	12/16/2019	2. Third Party Cybersecurity Risk Management Standard interim draft
3	4/2/2020	3. Third Party Cybersecurity Risk Management Standard final draft
4	9/1/2020	4. Third Party Cybersecurity Risk Management Standard initial release

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### 1. PURPOSE / SCOPE

- 1.1. This plan documents PPL Electric Utilities Corporation’s (“PPL EU”) plan for Supply Chain Risk Management, also known as “Plan”. The Plan addresses all acquisitions, including non-contractual procurement, and digital or electronic sharing of Confidential or higher classified information without a contract. Additionally, the Plan covers NERC Reliability Standard CIP-013, Cyber Security – Cyber Security Supply Chain Risk Management.
- 1.2. The Plan covers all acquisitions by and for PPL Services Corporation, PPL EU Services Corporation and PPL EU, collectively referred to as PPL in this document.
- 1.3. In some cases, corporate policies and procedures contain provisions that are more stringent than the requirements of the NERC Reliability Standards. Examples, include, but are not limited to:
  - 1.3.1. PPL may conduct a quarterly review even though the NERC Reliability Standard requires an annual review.
  - 1.3.2. Requirements in the Plan that exceed CIP-003, Cyber Security – Security Management Controls, Attachment 1 for Low Impact Cyber Assets.
    - 1.3.2.1. For purposes of cyber risk assessment, PPL treats all high, medium and low impact NERC CIP Cyber Assets the same.

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1.3.2.1.1. BES Cyber Assets (BCA), Protected Cyber Assets (PCA), Cyber Assets used in the Electronic Access Control or Monitoring Systems (EACMS) of the BCS's and Cyber Assets used in the Physical Access Control System (PACS) of the Physical Security Perimeter (PSP) are collectively referred to as NERC CIP Cyber Assets.

1.3.3. To the extent PPL procedural requirements are not met yet exceed NERC Reliability Standards requirements, this is not a potential non-compliance condition. Rather it is considered a non-conforming condition. Any non-conforming condition is assessed against the NERC Reliability Standards via EU-NERC-100, PPL EU NERC Compliance Governance Process.

## 2. RESPONSIBILITY

- 2.1. PPL EU NERC CIP Senior Manager
  - 2.1.1. Overall responsibility and authority for leading and managing PPL's implementation of, and adherence to, NERC CIP Standards.
  - 2.1.2. Review and approve this Plan
  - 2.1.3. Review and approve, as appropriate, any exceptions to this Plan.
  - 2.1.4. All references to CIP Senior Manager refer to the CIP Senior Manager or delegate.
- 2.2. Director – Cyber Security PA CISO
  - 2.2.1. Process Owner for Cyber Security Risk Management.
  - 2.2.2. Facilitate Cyber Security Risk Assessment Process
- 2.3. Director – Supply Chain or delegate
  - 2.3.1. Provide necessary support for process and team participation.
- 2.4. PPL Vendor Risk Assessment Team Members
  - 2.4.1. Participate in team meetings as required.
  - 2.4.2. Perform Risk Assessment.
  - 2.4.3. Participate in the generation of the Vendor Risk Mitigation Matrix and Vendor Risk Assessment Summary.
- 2.5. PPL Office of General Counsel (“OGC”)
  - 2.5.1. Perform tasks laid out in the Plan related to software contracts without negotiable terms.
  - 2.5.2. Provide legal advice in support of the Plan.
- 2.6. PPL Employees and Contractors
  - 2.6.1. Must adhere to this process for all acquisitions of hardware (goods, equipment - anything physical, material), software (includes software as a service, cloud services, online subscriptions) and services as well as in sharing of confidential and higher

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classified information. Hardware may be collectively referred to as products and software and services may collectively be referred to as services throughout this document.

2.6.2. Acquisition during storms is not an exception.

### 3. APPLICABILITY

- 3.1. This document applies to all PPL employees and contractors performing tasks directly for, or in support of PPL.
- 3.2. All such relevant employees and contractors are expected to fully comply with the Plan.

### 4. TERMS AND DEFINITIONS

- 4.1. Refer to NERC Glossary of Terms.
- 4.2. Refer to PPL EU program EU-NERC-PGM-Definitions.

### 5. RISK ASSESSMENT OVERVIEW

- 5.1. PPL implements a risk management process for the acquisition of all hardware, software and services, and for the digital or electronic sharing of Confidential or higher classified information that is not part of a procurement contract. PPL applies this process both to procuring and installing vendor equipment and software and transitioning from one vendor(s) to another vendor(s) for an existing product or service.
- 5.2. This risk management process uses tiering of a Vendor based on the products and services provided and the electronic/digital access to information and PPL systems by that Vendor. Tier 1 represents the highest potential risk and hence has the most rigorous assessment process and a more frequent re-assessment timeframe.
- 5.3. PPL's vendor risk assessment team ("Tier 1 and 2 Vendor Assessment Team") is a cross functional group that performs a risk assessment prior to PPL contracting for, procuring, or acquiring any products or services from Tier 1 and Tier 2 Vendors or digital or electronic sharing of Confidential, or higher classified information with outside parties when not part of a procurement contract.
- 5.4. Because they encompass lower risk, PPL does not utilize the risk assessment team for Tier 3, Tier 4 or Tier 5. See Sections 7.2.3 and 7.2.4 for more details.
- 5.5. PPL does not use the team approach for software contracts without negotiable terms. See Section 7.2.5 for more details.
- 5.6. Once an assessment process is completed, mitigating actions are tracked and the Vendor is re-assessed on a frequency designated by the then current tier assignment. See Section 7.4.1 for more details.
- 5.7. PPL maintains a list of Pre-Approved services and products that are deemed to provide little, or no cyber risk and as a result, do not need to go through the tiering process.

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- 5.8. For purposes of this document, an order, purchase order and agreement or contract to purchase product or services is referred to as a contract, unless otherwise noted.
- 5.9. For purposes of this document, information includes intellectual property, including, but not limited to, copyrights, trademarks, patents, trade secrets and other business, confidential or proprietary data and information.

## 6. GENERAL PROCESS INFORMATION

- 6.1. All contracted services and acquisitions, other than software contracts without negotiable terms and digital or electronic sharing of Confidential, or higher classified information without a procurement contract, require a requisition to be entered and approved in Asset Suite. This can be in the form of a services entry (“CR”), contract change request or a materials request (“MR”), here after referred to as a requisition unless notated otherwise. See Section 6.2 for MR specific information.
  - 6.1.1. New Vendors are assessed in the course of establishing new contracts for products and services.
  - 6.1.2. For contracts with terms beyond a year, the Vendor is re-evaluated in a timeframe based on the tier assignment for the Vendor, See Section 7.4.2.
  - 6.1.3. Each Vendor is tiered based on the description or scope of work presented. A Vendor’s tier assignment changes if a subsequent description or scope of work represents a higher risk tier.
  - 6.1.4. Initial assessment for existing Vendors
    - 6.1.4.1. All existing Tier 1 NERC CIP Cyber Asset Vendors are assessed by October 1, 2020. Thereafter, assessment is on a yearly basis.
      - 6.1.4.1.1. All existing non-NERC CIP Cyber Asset Vendors are also completed by October 1, 2020, or shortly thereafter.
      - 6.1.4.1.2. For engagements with new Vendors that are slated to perform Tier 1 work, the cyber risk assessments are completed prior to signing of the initial contract.
    - 6.1.4.2. Existing Tier 2 Vendors are initially assessed by June 30, 2022. Thereafter, re-evaluation follows the timeframe prescribed by the Tier, see Section 7.4.2.
    - 6.1.4.3. During the transitional phase, for engagement with new Vendors slated to perform Tier 2 work, assessments are prioritized based on the Tier with an effort to complete as many as feasible prior to signing new contracts. Any assessments not completed prior to signing of the contracts are completed as soon as prioritization allows but in no case later than June 30, 2022.
    - 6.1.4.4. Assessments for Tier 3 Vendors are performed as requested and are fit in as time allows. At this time, there is no deadline for completing the assessment for all existing Tier 3 Vendors or for new Tier 3 Vendors.
  - 6.1.5. All new software (including applications and trial versions) requests run through the **New Technology Approval Process (“NTAP”)** prior to a requestor entering a requisition in Asset Suite. The IT Cybersecurity representative confirms completion of

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that process by checking spreadsheet of approved assets provided by the IT Asset Management group.

- 6.1.6. The process described in the Plan applies both to procuring and installing vendor equipment and software and transitioning from one vendor(s) to another vendor(s) for an existing product or service.
- 6.1.7. The requestor is responsible for all activities below except for the physical entry of the information into Asset Suite. The requestor can have a designate to perform the physical entry into Asset Suite.
- 6.1.8. **If the Vendor has an Asset Suite status of "Expelled", the Vendor may be on the Deny List and not available for selection. The requestor contacts Supply Chain to confirm that there is not another reason the Vendor is flagged as "Expelled".**
- 6.1.9. Within Asset Suite, a Vendor designation is not required on a requisition.
  - 6.1.9.1. If a Vendor is not in the Vendor Master within Asset Suite, the requestor enters the requisition without a Vendor and contacts the Category Manager. With the contact, the Category Manager starts the process to vet and enter the Vendor into the Vendor Master.
  - 6.1.9.2. In other circumstances, the requestor may not want to designate the Vendor. In these cases, the Vendor decision is made by Supply Chain. This decision is made by various means which include, but are not limited to, the use of an existing Vendor relationship or via a bidding process (see Section 6.10).
- 6.2. MR's
  - 6.2.1. Catalog ID Items
    - 6.2.1.1. For catalog ID items, initially, Supply Chain notifies a representative from the organization requesting the contracted item or service ("Business Line") to answer the Tiering Questionnaire to establish the Tier for all items that are not included in the Pre-Approved List.
    - 6.2.1.2. Based on the Tier, the risk assessment is completed for the supplying Vendor, or the item is reviewed for addition to the Pre-Approved List. As the quantity on the purchase order expires, if the price and quantity are the only terms changing, Supply Chain can reorder without a new assessment as long as there is an existing cyber risk assessment in the timeframe allowed for the assigned tier of the Vendor.
    - 6.2.1.3. When a new catalog ID item is set-up, if the product is not on the Pre-Approved List, a Vendor risk assessment is completed based on the tier of the product. If a Vendor assessment is already in place within the allowed timeframe for the assigned tier, no action is required.
  - 6.2.2. Non-catalog ID items
    - 6.2.2.1. For the Transmission and Distribution Business Lines, Tiering Questionnaires are not required to be attached to an MR by the requestor.
      - 6.2.2.1.1. When the Category Manager receives the MR, they review the material against the Pre-Approved List and the Deny List.

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- 6.2.2.1.1.1. If the product(s) is not on the Pre-Approved List, the Category Manager works with the requestor, as necessary, to populate a Tiering Questionnaire for the product.
  - 6.2.2.1.1.1.1. The Requestor attaches the Tiering Questionnaire to the Notes section prior to the delegation of authority approval.
  - 6.2.2.1.1.1.2. The Category Manager proceeds with appropriate cyber risk assessment activities based on the Tier of the product.
- 6.2.2.1.2. If the product(s) is on the Pre-Approved List, the Category Manager processes the MR without a cyber risk assessment.
- 6.2.2.1.3. If the Vendor or component are on the Deny List, the Category Manager works with the requestor to resolve. See Section 6.8 for more information on the Deny List.
- 6.2.2.2. All other MR's require a Tiering Questionnaire. The Tiering Questionnaire is entered into the Notes section when entering the MR. See Section 6.4 for more information on the Tiering Questionnaire.
- 6.3. Multiple tiered products/services on the same requisition.
  - 6.3.1. If all the tiered products and/or services being requested have the same Vendor designated, the requestor submits a single Tiering Questionnaire that encompasses the sum of the risk. In other words, responds to the questions in consideration of all services and products being requested.
- 6.4. Tiering Questionnaire
  - 6.4.1. Along with the requisition, the requestor fills out the Tiering Questionnaire (Attachment 3). Note: For software contracts without negotiable terms, the Tiering Questionnaire is replaced by the –Software Contract Without Negotiable Terms Questionnaire (Attachment 4; see Section 7.2.5) and a requisition is not entered in Asset Suite.
  - 6.4.2. If the product/service is for a non-cyber related commodity product/service, check the Pre-Approved List.
    - 6.4.2.1. If the product/service is on the list, a Tiering Questionnaire and risk assessment are not required.
    - 6.4.2.2. If the product/service is not on the list, respond to the questions in the tier evaluation and additional scope sections on the Tiering Questionnaire and submit with the requisition.
  - 6.4.3. Tiering Questionnaire (Attachment 3) is interactive to determine the tier based on Y/N responses to the questions.

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- 6.4.4. The Tiering Questionnaires are attached by the requester with the requisition in the Scope of Work section of Asset Suite.
- 6.4.5. Supply Chain works with the requestor to make sure all applicable information in the Tiering Questionnaire is complete.
- 6.5. Pre-Approved List
  - 6.5.1. Acquisitions of, or contracts related to, products and services on the Pre-Approved List do not need a cyber risk assessment for the Vendors providing these products and services.
    - 6.5.1.1. A Vendor selling Pre-Approved products or services may still require a tier assignment and assessment if it also provides other products or services that meet the criteria for a Tier 1 or Tier 2 Vendor.
    - 6.5.1.2. Any items on the Pre-Approved list may be purchased via Corporate Card or via expense reimbursement. See Corporate Card CP 605 for more information regarding use of the Corporate Card.
    - 6.5.1.3. If purchasing something that is not on the Pre-Approved list, contact Supply Chain for assistance.
  - 6.5.2. At least once a quarter, Supply Chain initiates a review of requisitions submitted as Tier 5 and any other potentially low risk products/services pro-actively submitted by PPL users.
  - 6.5.3. A team (the Tier 5 Review Team) reviews the Tier 5 requisitions and user inputs for potential addition to the Pre-Approved List.
    - 6.5.3.1. The Tier 5 Review Team consists of at least one Category Manager, one Supply Chain Manager and a representative from IT Cybersecurity. The team consults with other SME's, as needed, to understand the product/service.
    - 6.5.3.2. After reviewing, if the products/services have the potential for a future requisition and are deemed to be a little or no cyber risk, IT Cybersecurity adds the products/service to the Pre-Approved List.
    - 6.5.3.3. The Pre-Approved List is posted within the Supply Chain SharePoint site: <https://intranet.sp.ppl.com/sites/supplychain/Pages/Home.aspx> in the NERC-CIP-013-and-Enterprise-Cybersecurityfolder. The Pre-Approved List is maintained by IT Cybersecurity.
    - 6.5.3.4. IT Cybersecurity also documents the review meeting to capture the date of review, items reviewed, result of review and attendees that participated in the decision to make additions to the Pre-Approved List.
    - 6.5.3.5. IT Cybersecurity maintains documentation of the review in the SChain CyberRiskAssessment docs\Archived Documents folder within the \\ppl.com\pplcorp\BusData\ISSData\IAG shared drive location for future reference.
- 6.6. Contingency Vendors for Emergency Situations

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- 6.6.1. As part of the annual review per CP 201, Business Continuity Plans are reviewed to assess the need for Contingency Vendors to be pre-assessed to ensure that PPL has the depth of Vendors that may be required in an emergency.
- 6.6.2. A representative from the applicable PPL department or line of business (“Business Line”) that needs the Contingency Vendor submits a requisition into Asset Suite with an estimated value along with a Tiering Questionnaire that reflects the sum of all of the work this Vendor could potentially be asked to provide in terms of services, hardware or software.
- 6.6.3. All identified Contingency Vendors go through the cybersecurity risk assessment process as outlined in this Plan.
- 6.7. Restoration Contractors via Mutual Assistance
  - 6.7.1. In certain circumstance, PPL can engage resources from other utilities for storm restorative work.
  - 6.7.2. These resources can be in the form of other utilities’ own restoration crews or those of their contractors.
  - 6.7.3. These crews are requested via the Southeast Electrical Exchange (“SEE”) or the North Atlantic Mutual Assistance Group (“NAMAG”).
  - 6.7.4. For crews obtained via either of these organizations, crew members generally do not require access to a PPL digital tool to provide information related to crew availability and activities.
  - 6.7.5. If crews are asked to utilize a PPL digital tool, PPL relies on the sponsoring organization for their risk assessment and management. As a result, there is no requirement for PPL to perform a cyber risk assessment.
- 6.8. Deny List
  - 6.8.1. The Deny List contains the names of Vendors, their known affiliates, components, services, or products that cannot be utilized by PPL in whole, or in part.
  - 6.8.2. The Deny List is accessible within the Supply Chain SharePoint site: <https://intranet.sp.ppl.com/sites/supplychain/Pages/Home.aspx> in the NERC-CIP-013-and-Enterprise-Cybersecurityfolder. The Deny List is maintained by IT Cybersecurity.
    - 6.8.2.1. Updates from the Department of Commerce or Department of Homeland Security come from Enterprise Security to the IT Cybersecurity Director. This information is then communicated to the person maintaining the Deny List.
  - 6.8.3. When an update is made to the Deny List by IT Cybersecurity, the Supply Chain Programs group is notified.
    - 6.8.3.1. For Vendor additions, the Supply Chain Programs group either updates the Vendor status to “Expelled” if PPL is already engaged with the Vendor or enters the Vendor as a Deny List record if PPL is not already engaged with the Vendor.

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- 6.8.3.1.1. In addition, the Supply Chain Programs group checks the Asset Suite Vendor Master report to see if there are any open engagements with the Vendor added to the Deny List.
  - 6.8.3.1.2. If there are any active contracts with a Vendor recently added to the Deny List, the Supplier Manager contacts the applicable Category Manager for that engagement (the analyst on the contract or PO). The Category Manager contacts the requester(s), or their designee, to discuss options and additional parties to be included in the decision on how to proceed to identify appropriate mitigations to identified risk or to request an exception.
  - 6.8.3.2. For component and system additions to the Deny List, Supply Chain investigates existing uses or installations of the additions.
  - 6.8.4. The applicable Category Manager works with the requester(s) or their designee to evaluate risk of all existing and prior engagements to determine actions to reduce or eliminate risk. This effort is initiated within 30 days of the addition to the Deny List.
  - 6.8.5. All requesters are responsible for checking the Deny List before entering a requisition.
  - 6.8.6. To avoid delays late in the planning and design process, the Deny List is checked as early as possible to confirm that there is no consideration for services, products or Vendors that are on the Deny List. This check is completed again prior to submission of the requisition for the system.
  - 6.8.7. Upon receiving a requisition within Asset Suite, Supply Chain checks the Vendor and all Vendors defined on the bill of materials as well as services, and products utilized, in whole or in part, against the Deny List.
  - 6.8.8. The use (or continued use) of a Vendor, product or service on the Deny List is allowed on an exception basis only. See Section 8.1.3.
  - 6.8.9. Once a calendar quarter, with a 15-day grace period, the Deny List on the shared drive is compared to a Supply Chain report that captures the Expelled status with Deny List in the notes to make sure the two stay in sync. Supply Chain completes this reconciliation and considers all approved exceptions and documents on the record of the quarterly review tab of the Deny List file.
- 6.9. Country of Origin
- 6.9.1. The list of originating countries of concern is maintained within the same file as the Deny List on the Supply Chain Sharepoint site. See Section 6.8.2 for the full path and the update process which is the same as the Deny List.
  - 6.9.2. This list reflects countries that the United States government has designated as a concern if they are the country of origin for a product (programmable hardware or software). Is the design, manufacture, assembly, development, or support for the product or service in one of these countries?
  - 6.9.3. This concern also extends to the location for cloud hosting services and other data storage and processing facilities.

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- 6.9.4. If a source of the product is on the Country of Origin list, a risk informed review is undertaken as part of the cyber risk assessment.
- 6.9.5. Rejection of the contract, more contractual controls as well as additional mitigating controls (e.g. increased monitoring, shielding, disabling of parts of the product, etc.) may be warranted depending on the nature and use of the product/service.
- 6.10. Vendor Bidding
  - 6.10.1. If a Vendor is not specified on the requisition, Supply Chain may decide to put the request out to bid.
  - 6.10.2. If digital or electronic Confidential, or higher classified information is part of the bid package, a risk assessment for the Vendor needs to be completed before this information is disseminated as part of the bid process.
  - 6.10.3. Vendors on the Deny List are not included in requests for bid.
  - 6.10.4. Assuming there is more than one bid returned, Supply Chain reviews the bids with the stakeholder team and together decide on a short list of Vendors based on the commercial terms and technical evaluations to the bid requirements. Prior to awarding any contract or PO, Supply Chain confirms the necessary Vendor cyber assessment is in place.
- 6.11. With receipt of a requisition and Tiering Questionnaire for a Tier 1 or Tier 2 Vendor, Supply Chain checks the Vendor Master in Asset Suite for the timing and level of any previous risk assessments for other products or services for the Vendor. If the most recent requisition is a higher risk tier than the previous assessment or the assessment has expired, a new assessment needs to be completed. See Section 7.4.2 for the re-assessment timing for each tier.
- 6.12. The Category Manager notifies the Business Line to provide a new Tiering Questionnaire if there is a change in scope that impacts cyber exposure between the initial review and the signing of the contract. In addition, if the Business Line submits a Contract Change Request a different tier assignment can result based on different responses to the Tiering Questionnaire. If a change in scope is not cyber related (i.e. the responses on the Tiering Questionnaire do not change), a new Tiering Questionnaire is not required.
  - 6.12.1. If the result is a higher risk tier assignment, a risk assessment for the higher risk tier needs to be completed for the Vendor.
- 6.13. Review of design changes to a NERC CIP Cyber Asset
  - 6.13.1. There is a process to validate that a change to a NERC CIP Cyber Asset - whether that be a Vendor or component change, does not adversely impact controls for the asset. Details can be found in EU-NERC-CIP-120, PPL Electric Utilities Cyber Security Testing.

## **7. RISK ASSESSMENT PROCESS**

### **7.1. Elements for Risk Assessment**

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- 7.1.1. For Tier 1 and Tier 2 Vendors, a third-party assessment is encouraged and a Vendor Risk Questionnaire (“VRQ”) is required. These pieces of information, along with the Tiering Questionnaire are provided to IT Cybersecurity by Supply Chain.
- 7.1.2. For Tier 3 Vendors, a third-party assessment and a vendor risk questionnaire are optional and are to be utilized by request only if available and there is a specific concern.
- 7.1.3. An assessment report, supplied by the Vendor, to the NATF Vendor Cyber Security Criteria takes the place of both the third-party assessment and the VRQ.
- 7.1.4. PPL reserves the option to engage a third party to provide cyber risk assessment and validation services. These services utilize the NATF framework. If these services include assessment and validation, they stand in place of the VRQ and third-party assessment outlined below.
- 7.1.5. Third-Party Assessment
  - 7.1.5.1. PPL considers third-party assessments with the following attributes:
    - 7.1.5.1.1. Third-party assessor(s) must be independent and have credentials (e.g. SOC 2’s are performed by Certified Public Accountants in accordance with attestation standards established by the American Institute of CPA’s (AICPA) or International Organization for Standardization (“ISO”) certification audits are performed by ISO certified auditors).
  - 7.1.5.2. Acceptable third-party assessments.
    - 7.1.5.2.1. Vendor provides an assessment report to the North America Transmission Forum (“NATF”) Vendor Cyber Security Criteria that is within the time limits documented in Attachment 2.
    - 7.1.5.2.2. Vendor provides a SSAE 18 SOC2 Type 2 report that is fewer than 18 months since completion of the last assessment for Tier 1 Vendors; fewer than 24 months since completion of the last assessment for Tier 2 and Tier 3 Vendors.
    - 7.1.5.2.3. Vendor provides an ISO 27001 certificate within the last three years or a summary of the most recent annual external review.
- 7.1.6. VRQ
  - 7.1.6.1. Supply Chain provides the VRQ to Vendors. Supply Chain works with IT Cybersecurity and the Vendor to resolve any questions or issues.
    - 7.1.6.1.1. The VRQ is managed by IT Cybersecurity.
    - 7.1.6.1.2. If a Vendor does not return a VRQ or returns their own version, IT Cybersecurity reserves the option to populate a VRQ on behalf of the Vendor if they have enough information to provide value to this process.
    - 7.1.6.1.3. The Vendor may provide an assessment to the NATF criteria per Section 7.1.3.

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7.1.6.1.4. If PPL chooses to use a third-party assessor (per Section 7.1.4), Supply Chain notifies IT Cybersecurity of the need for an assessment rather than sending the VRQ request to the Vendor.

7.1.6.1.5. IT Cybersecurity works with the third-party assessor to get the assessment completed.

**7.1.7. Industry Information**

7.1.7.1. PPL may leverage external sources for further information regarding its Vendors and potential Vendors, e.g. BitSight.

**7.2. Vendor Risk Assessment**

**7.2.1. IT Cybersecurity reviews the available inputs – Third-Party assessments, VRQ responses and all other available information.**

7.2.1.1. When reviewing the VRQ, IT Cybersecurity works with the Vendor to resolve any missing information or additional questions for clarity.

7.2.1.2. Based on the tiering requested for the Vendor, IT Cybersecurity assesses the capability of the Vendor to perform the necessary protections for the relevant scope of work.

7.2.1.3. If the Vendor is deemed to be unsuitable, based on its cybersecurity policies and procedures, or lack thereof, to fully manage the scope of the requested tier, IT Cybersecurity identifies any potential mitigating actions to reduce the risk.

**7.2.2. Tier 1 and 2 Vendor Risk Assessment**

7.2.2.1. Current and proposed Tier 1 and 2 Vendors are assessed by the Tier 1 and 2 Vendor Assessment Team which includes representation from: the group desiring contracting or continuation of products or services, IT Cybersecurity, Supply Chain, OGC, and Risk Management. In the absence of the designated representative for a specific group, the specific group may send a delegate.

7.2.2.2. There generally is a standing, weekly timeslot for the Tier 1 and 2 Vendor Assessment Team to meet. The day before the meeting, IT Cybersecurity decides if material is ready for review for either new or existing Vendors. If not, IT Cybersecurity sends a cancellation notice via email.

7.2.2.3. Prior to the Tier 1 and 2 Vendor Assessment Team review meeting, requirements and risks are updated on the Vendor Risk Mitigation Matrix based on information reviewed.

7.2.2.4. Tier 1 and 2 Vendor Assessment Team reviews the available elements of the risk assessment (e.g. third-party assessments, VRQ and industry reports) for PPL's Tier 1 and Tier 2 Vendors.

7.2.2.5. When looking at risks, the Tier 1 and 2 Vendor Assessment Team focuses on the higher risk items first and then medium risk items with the goal of identifying actions to either eliminate the risk or reduce the risk to low.

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- 7.2.2.6. PPL recognizes that not all Vendors are able to adhere to or support all desired cybersecurity policies and procedures. In the event a Vendor is unable to support a desired position, and enough mitigating factors do not exist, PPL, when possible, may implement compensating controls to reduce the associated risk. Alternately, the Tier 1 and 2 Vendor Assessment Team identifies actions the Vendor could take to reduce the identified risk. The Tier 1 and 2 Vendor Assessment Team captures identified relevant risks, mitigation activities and residual risk on the Vendor Risk Mitigation Matrix (Attachment 5).
  - 7.2.2.6.1. If there are mitigation actions to be put in place that are to be owned by the Vendor, there needs to be documentation around the timing of the implementation for these actions.
  - 7.2.2.6.2. The Tier 1 and 2 Vendor Assessment Team also discusses alternatives if the Vendor does not agree to sufficient mitigation actions.
- 7.2.2.7. Supply Chain includes Vendor-owned mitigation actions in contract negotiations.
- 7.2.2.8. In assessing risk, the Tier 1 and 2 Vendor Assessment Team considers the elements of risk assessment, relevant information, including a team member's knowledge and experience, the scope of the application, any identified mitigation actions and any other information supplied by an individual team member. A recommendation to proceed, or not, is based on the collection of knowledge and experience given the information available regarding the level of residual risk, the probability of the risk being experienced and the consequences along with options for alternatives to meet the needs of the business and the risk tolerance of the Business Line.
- 7.2.2.9. Output from the Tier 1 and 2 Vendor Assessment Team is in the form of the Vendor Risk Mitigation Matrix (Attachment 5) and the Vendor Risk Assessment Summary (Attachment 6).
  - 7.2.2.9.1. A completed Vendor Risk Assessment Summary provides the approvers the necessary information to render a decision to proceed, or not. It is not for funding purposes and does not fulfill requirements for an Investment Proposal.
  - 7.2.2.10. If desired, proceed to approval, Section 7.3.
- 7.2.3. Tier 3 Vendor Risk Assessment
  - 7.2.3.1. For Tier 3 Vendors, IT Cybersecurity may choose to, but is not required to, review available VRQ, or equivalent, and the third-party audit and assessment reports and any other available information. No team or cyber risk assessment is required.
  - 7.2.3.2. IT Cybersecurity completes the Vendor Risk Mitigation Matrix. If applicable, OGC offers input on items from the software contract review.
  - 7.2.3.3. IT Cybersecurity provides the Vendor Risk Mitigation Matrix to the Business Line representative.

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- 7.2.3.4. The Business Line representative, OGC, if applicable and the IT Cybersecurity representative complete the Vendor Risk Assessment Summary with a recommendation.
- 7.2.3.5. If desired, proceed to approval, Section 7.3.
- 7.2.4. Tier 4 and Tier 5 Vendor Risk Assessment
  - 7.2.4.1. Tier 4 and Tier 5 Vendors are not required to go through a cyber risk assessment since the products or services they are providing do not meet the criteria set for any of the other tiers. By the nature of the products and services provided by these Vendors, they do not pose a level of cyber risk to the organization that deems an assessment.
- 7.2.5. Software Contracts Without Negotiable Terms
  - 7.2.5.1. Many types of software do not allow contracts with negotiable terms. This includes, but is not limited to, free and open source software.
  - 7.2.5.2. Acquisitions of software without negotiable terms (e.g. Open source or free software) are not tiered; however, they need a risk assessment before installation and/or use.
  - 7.2.5.3. The Requestor sends an email to OGC and the IT Cybersecurity representatives with a "Title of software" review in the subject line and attaches the license agreement associated with the requested software and the Software Contract Without Negotiable Terms Questionnaire (Attachment 4). If the software is new, it goes through the NTAP process before requesting review.
    - 7.2.5.3.1. The Software Contract Without Negotiable Terms Questionnaire is intended to capture information regarding the intended use and potential exposure in utilizing the software.
  - 7.2.5.4. Risk Assessment
    - 7.2.5.4.1. IT Cybersecurity assesses the risk utilizing all available information.
    - 7.2.5.4.2. For open source software, there is no Vendor, so a VRQ and third-party assessment are not viable options. For free software, a VRQ is used, if available.
    - 7.2.5.4.3. Other options include utilization of the user groups and various sites on the internet, for evidence of authenticity and trustworthiness.
    - 7.2.5.4.4. OGC reviews any available license agreements or other terms of use to highlight embedded risk.
    - 7.2.5.4.5. OGC and IT Cybersecurity fill out the appropriate sections of the Vendor Risk Assessment Summary.
    - 7.2.5.4.6. The Requestor fills out the balance of the Vendor Risk Assessment Summary.

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- 7.2.5.4.7. The Requestor is responsible for obtaining the necessary approvals to proceed.
- 7.2.6. Sharing of Confidential, or higher classified information in digital or electronic form without a procurement contract.
  - 7.2.6.1. There is no entry into Asset Suite since there is no acquisition associated with these relationships.
  - 7.2.6.2. In certain situations, PPL will share digital or electronic Confidential or other classified information without a procurement contract, for example for the purpose of evaluating a potential business relationship or university research or industry analysis/benchmarking. Even though there is no acquisition, PPL still evaluates the counterparty's ability to protect the information shared in a manner commensurate with the type of information.
  - 7.2.6.3. The requestor completes the Tiering Questionnaire that directs the path of analysis based on the tier.
    - 7.2.6.3.1. If required, the requestor supplies the VRQ to the third-party and provides the response file to the IT Cybersecurity team for review. It should be provided via the group mailbox – ISD, Vendor Risk.
    - 7.2.6.3.2. As necessary, the requestor works with OGC to provide an appropriate contract with the necessary language based on the information and the tier. If the third-party does not respond to the VRQ, Supply Chain informs OGC.
  - 7.2.6.4. Instead of information being stored in Asset Suite, the IT Cybersecurity is responsible to make sure all required documentation (see Section 7.3.5.4) is saved to the SChain CyberRiskAssessment docs folder within the \\ppl.com\pplcorp\BusData\ISDDData\IAG shared drive location.
  - 7.2.6.5. The above subscribed process for cyber risk assessing third-parties PPL engages with in sharing of electronic or digital Confidential or higher classified information shall not apply to information requested or required by the following entities:
    - 7.2.6.5.1. Government entities, including courts, regulatory agencies, or legislators (e.g., FERC, the PA PUC, the IRS)
    - 7.2.6.5.2. Regional transmission organizations or independent system operators (i.e., PJM)
    - 7.2.6.5.3. The North American Electric Reliability Corporation (NERC) and regional entities (i.e., ReliabilityFirst)
    - 7.2.6.5.4. Outside auditors (i.e., Deloitte)
    - 7.2.6.5.5. Any other entity designated by the PPL Office of General Counsel.
  - 7.2.6.6. Additional exclusions: This cyber risk assessment process for third parties PPL engages in sharing of digital or electronic Confidential or higher classified information shall also not apply in the following situations:

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7.2.6.6.1. Information shared in the normal course of business with interconnecting utilities, power generators, or customers for purpose of interconnection with PPL's electric system, regardless of whether a service agreement is signed.

7.2.6.6.2. Information shared in the normal course of business related to PPL's structures or designs for purpose of attaching third party facilities to PPL equipment (e.g., cellular phone facilities, fiber attachments).

### 7.3. Approval to Proceed

7.3.1. In order to ensure there has not been a relevant addition to the Deny List during the assessment process, before contract signing, Supply Chain confirms that neither the Vendor nor the components or system (along with components thereof) have been added to the Deny List. If components or the Vendor are on the list, the proposal cannot continue. Supply Chain works with the Business Line to evaluate an alternative unless the Business Line decides to request approval for an exception. See Section 8.1.3.

7.3.2. The Business Line representative completes a new Tiering Questionnaire.

7.3.2.1. The responses are reviewed as part of the review process just before approval to verify the Tiering Questionnaire properly reflects the current understanding of the engagement with that Vendor.

7.3.2.1.1. If the tier assignment changes from the original submission, the risk assessment needs to be re-evaluated before proceeding.

7.3.2.2. This 2nd Tiering Questionnaire is kept in the SChain CyberRiskAssessment docs folder.

7.3.3. The Business Line representative provides the Vendor Risk Assessment Summary and the Vendor Risk Mitigation Matrix to the approvers. These documents capture identified risks as well as opportunities to mitigate.

7.3.4. The management level and Business Lines required for final approval and sign-off are based on the tiering for the Vendor and the assessment recommendation – see Tier Approval Table below.

7.3.4.1. Sign-off by the Business Line requesting the use of the Vendor, indicates acceptance of the Vendor with the identified residual risk and mitigation and controls plans.

7.3.4.2. Sign-off by the other members listed in the matrix below indicates acceptance of their Business Line's responsibility for completion of the identified mitigation plans.

7.3.4.3. When the review is a negative recommendation and the Business Line decides to not proceed, the Business Line uses the Summary file to capture their plan to temporarily or permanently dis-engage from the Vendor.

7.3.4.3.1. If the plan is to temporarily not utilize the Vendor, any mitigating actions are captured and tracked to completion. At that time, the

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Vendor is re-evaluated in the hope that the Business Line can re-engage.

7.3.4.3.2. If the intent is to not use the Vendor on a long-term basis, mitigating actions are not worked or tracked.

7.3.4.3.3. In both cases, the review documents are archived, and the mitigating actions captured accordingly.

7.3.4.4. Any Tier 3 reviews requested are performed informally. All concerns are shared with the Business Line and Supply Chain for them to proceed as they deem appropriate given the circumstances.

7.3.4.5. Tier Approval Table

Vendor Tier	Approvers to proceed when requesting Business Line is aligned with assessment recommendation given the residual risk	Approvers to Proceed if requesting Business Line wishes to proceed without assessment recommendation given the residual risk.
Tier 1 and Tier 2	Requesting Business Line Director Directors of Business Lines with mitigation ownership	Requesting Business Line VP, VP level for other Business Lines using/planning to use the Vendor and IT VP/CIO  Directors of Business Lines with mitigation ownership
Software Contracts Without Negotiable Terms	For BES Assets -IT Planning & Work Management Director and Requesting Business Line Director; otherwise, IT Operations Director	For BES Assets -IT Planning & Work Management Director and Requesting Business Line VP; otherwise, IT VP/CIO

7.3.5. Supply Chain works with OGC to finalize negotiations on a contract.

7.3.5.1. When negotiating a contract, OGC and Supply Chain include contract language to capture the applicable items outlined in the requirements for the tier and consider the Other Considerations listed in Attachment 2.

7.3.5.2. Upon the issuance of the contract, for new software, Supply Chain notifies the IT Asset Management team so preparation for deployment can proceed per the NTAP Procedure.

7.3.5.3. For software contracts without negotiable terms, IT Cybersecurity notifies the IT Asset Management team of successful completion of the assessment process to enable deployment.

7.3.5.4. Once the contract is fully executed, Supply Chain notifies IT Cybersecurity. IT Cybersecurity confirms that all the information, including expire date of the contract, is populated in the Vendor Inventory Template.

7.3.5.4.1. When sign-off is complete, the following documents are archived:

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- 7.3.5.4.1.1. Documents utilized in the assessment (i.e. VRQ, NATF assessment, SOC2 Type 2, ISO 27001 certificate). IT Cybersecurity is responsible for maintaining these documents within the PPLCybersecurity SharepointOnline site in the Vendor Risk Questionnaire (VRQ) section of GRC (Governance, Risk and Controls).
  - 7.3.5.4.2. 2nd Tiering Questionnaire (all but software contracts without negotiable terms)
  - 7.3.5.4.3. Software Contracts Without Negotiable Terms Questionnaire (if applicable)
  - 7.3.5.4.4. Copy of license agreement (for all software to be kept in Asset Suite except software contracts without negotiable terms which are to be kept in the shared drive location)
  - 7.3.5.4.5. Vendor Risk Mitigation Matrix (Tier 1 and Tier 2)
  - 7.3.5.4.6. Vendor Risk Assessment Summary with signatures (Tier 1 and Tier 2, software contracts without negotiable terms)
  - 7.3.5.4.7. Unless otherwise noted, documents are archived in the SChain CyberRiskAssessment docs\Archived Documents folder within the \\ppl.com\pplcorp\BusData\ISDDData\IAG shared drive location for future reference.
  - 7.3.5.4.8. IT Cybersecurity is responsible to make sure all documents are archived once contracts are signed.
  - 7.3.5.4.9. Each Vendor has its own subfolder within the Archived documents folder. The next sub folder should be the Tier and date (e.g., Tier 1\_20-02-15) where the date represents the date the risk assessment approvals were completed.
  - 7.3.5.4.10. IT Cybersecurity coordinates information entry into the Vendor Inventory Template and confirms completeness before approval. This file is also maintained in the SChain CyberRiskAssessment docs\Archived Documents folder within the \\ppl.com\pplcorp\BusData\ISDDData\IAG shared drive location.
  - 7.3.5.4.11. In a monthly process, Supply Chain reviews the Vendor Inventory Template to remove any contracts that have expired or have been completed. This removal is a relocation of contract information to the completed tab, not a deletion.
- 7.4. Mitigation and Recurring Assessments
- 7.4.1. Tracking of mitigation actions.
    - 7.4.1.1. All Vendor and PPL mitigation actions are tracked and reviewed by the Tier 1 and 2 Vendor Assessment Team for Tier 1 and Tier 2 or IT Cybersecurity representative for Tier 3 at a minimum of quarterly until they are

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documented as complete. The required completion date depends on the nature of the action and the timing of the associated risk.

- 7.4.1.1.1. Documentation for these reviews can be in the form of a tracking sheet with regular updates, emails, meeting notes, Vendor audits or an updated VRQ (or equivalent).
  - 7.4.1.1.2. The Contract Manager tracks Vendor owned mitigation actions and provides input back to either the Tier 1 and 2 Vendor Assessment Team or IT Cybersecurity for Tier 3 Vendors as items are completed.
  - 7.4.1.1.3. The Tier 1 and 2 Vendor Assessment Team, or IT Cybersecurity for Tier 3 Vendors, notifies the Contract Manager if Vendor owned mitigation actions are not making progress to completion in a timely manner. The Category Manager facilitates a supplier improvement plan, as needed.
  - 7.4.1.1.4. The Tier 1 and 2 Vendor Assessment Team, or IT Cybersecurity for Tier 3 Vendors, escalates to the Director of the appropriate organization if the mitigating actions owned by the organization are not making progress to completion in a timely manner.
- 7.4.2. PPL periodically reviews its Tier 1 and Tier 2 Vendors by:
- 7.4.2.1. For contracts that extend beyond the timeframe for the tier, Tier 1 Vendors need to be re-evaluated annually; Tier 2 every 3 years.
    - 7.4.2.1.1. Catalog parts (components with Catalog ID's in Asset Suite) are the exception, in that a new purchase order does not require a new assessment unless the terms and conditions, other than price and quantity, are changing from the last purchase order. See Section 6.2.1.
    - 7.4.2.1.2. Any renewals or new engagements with an existing Vendor during the assessment period, do not require a new technical review.
    - 7.4.2.1.3. However, since contractual terms are being negotiated, any degradation of the terms related to cyber protections compared to the previously completed review, require a new team review.
    - 7.4.2.1.4. This is an opportunity to add cyber security protections as appropriate.
  - 7.4.2.2. Request applicable updated elements of the risk assessment.
  - 7.4.2.3. Participants, led by IT Cybersecurity, generate an updated Vendor Risk Mitigation Matrix.
  - 7.4.2.4. A new risk assessment is completed, documented and approved, or not, in the same manner as if it were a new requisition.
- 7.4.3. The Contract Manager can call an interim review based on new information or notification of an issue (e.g. NERC notification, public announcement of a breach,

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bankruptcy filing, significant change in cybersecurity monitoring score, part of a merger or acquisition, financial concerns, assignment of the contract etc.).

7.4.3.1. The Category Manager reviews the Vendor Master Report to provide an entire list of open contracts or purchase orders with the Vendor.

7.4.3.2. The original risk assessment owners, or departmental counterparts, convene to review the situation and potential change in risk.

7.4.3.2.1. If there are multiple engagements, the risk assessment owners that need to meet are those for the highest-level tier of the contracts that are currently active.

7.4.3.3. A new risk assessment is completed, documented, and approved in the same manner as if it were a new requisition.

7.4.3.3.1. If the situation has changed such that approval is not requested or obtained, OGC and Supply Chain works with the Business Lines to extricate PPL from all open engagements.

## 8 RISK PLAN EXCEPTION PROCESS

### 8.1 Exception Processes

8.1.1 All PPL employees and contractors are expected to fully comply with this Plan.

8.1.2 For NERC CIP Cyber Asset Vendors, exceptions to the Plan need written approval, in advance from the PPL EU VP Transmission & Substations or from the NERC CIP Senior Manager.

#### 8.1.3. Deny List Exceptions

8.1.3.1. All Deny List exceptions must be approved by the Director of Cybersecurity PA and the Chief Information Officer prior to proceeding to review and approval by the Corporate Security Council.

8.1.3.2. The Business Line requesting the exception assembles the business justification and any other pertinent information and provides to the Director of Cybersecurity PA and the Chief Information Officer for review and approval. The next step is to provide the information to the Corporate Security Council for their review and final approval. This information is retained with the other assessment information in the SChain CyberRiskAssessment docs folder within the [\\ppl.com/pplcorp/BusData/SSDData/AG](https://ppl.com/pplcorp/BusData/SSDData/AG) shared drive location.

8.1.3.3. A contract cannot be executed until the final approval from the Corporate Security Council is completed.

8.1.3.4. Supply Chain ascertains that the approval of an exception to the Deny List is noted on the Vendor Inventory Template (Attachment 7).

## 9 REFERENCES

 PPL Electric Utilities	<b>EU-NERC-CIP-013</b> <b>PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan</b>	Custom ID: <b>EU-NERC-CIP-013</b> Revision: 2 Effective Date: 12/17/2020 Page 21 of 37
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- 9.1 CIP-003, Cyber Security, Security Management Controls
- 9.2 CIP-013, Cyber Security – Supply Chain Risk Management
- 9.3 Contract Compliance Audit Process
- 9.4 CP 201 Preparedness/Response and Business Continuity Planning for Emergencies
- 9.5 CP 208, Facility Access Control
- 9.6 CP-403, Information Security
- 9.7 CP-404, Information Classification and Handling
- 9.8 CP-405, Electronic Information Security
- 9.9 CP-407, Records Management
- 9.10 CP-605, Corporate Card
- 9.11 ESS-07, Third Party Cybersecurity Risk Management
- 9.12 EU-NERC-CIP-020, PPL Electric Utilities Coordination of Interconnection Studies
- 9.13 EU-NERC-CIP-030, PPL EU NERC CIP Change Management
- 9.14 EU-NERC-100, PPL EU NERC Compliance Governance Process
- 9.15 EU-NERC-CIP-120, PPL Electric Utilities Cyber Security Testing
- 9.16 EU-NERC-CIP-070, PPL EU Information Protection
- 9.17 EU-NERC-CIP-701, CIP Personnel Risk Assessment Procedure
- 9.18 EU-NERC-PGM-Definitions
- 9.19 GP-309, Procedures When Employees or Contractors with Electronic and/or Physical Access Leaves Company or Internally Transfers
- 9.20 NATF CIP-013 Implementation Guidance
- 9.21 NERC Reliability Standards
- 9.22 NERC Security Guideline for the Electricity Sector – Supply Chain
- 9.23 NTAP Policy and Procedure

## **10 REGULATORY REQUIREMENTS**

- 10.1 This procedure complies with and supports the PPL EU NERC Compliance Program.
- 10.2 This procedure is reviewed at least once every 15 months.

## **11 TRAINING**

- 11.1 Updates are distributed via an email list, posted on PPL EU NERC Compliance website and/or announced at quarterly and weekly NERC compliance meetings.

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- 11.2 With initial roll-out, various communications were provided and videos and Job Aids posted to the Supply Chain SharePoint site:  
<https://intranet.sp.ppl.com/sites/supplychain/Pages/Home.aspx> in the NERC-CIP-013-and-Enterprise-Cybersecurity folder.

## 12 COMPLIANCE AND EXCEPTIONS

- 12.1 All PPL employees and contractors performing tasks directly for or in support of PPL are expected to fully comply and implement this Plan.
- 12.2 Exceptions to this Plan must be approved pursuant to Section 8.
- 12.3 Report any concerns with adherence to this Plan to your manager, the PPL EU NERC Compliance Officer, PPL EU NERC CIP Senior Manager, Manager – NERC & FERC Compliance, a member of the NERC & FERC Compliance, the Chief Information Officer or OGC.
- 12.3.1 Any individual receiving reported concerns should ensure the Mgr. – NERC & FERC Compliance is informed.

## 13 ATTACHMENTS

- 13.1 Attachment 1 – Vendor Tier Categories
- 13.2 Attachment 2 – Requirements by Tier
- 13.3 Attachment 3 – Tiering Questionnaire Form
- 13.4 Attachment 4 – Software Contracts Without Negotiable Terms Questionnaire Form
- 13.5 Attachment 5 – Vendor Risk Mitigation Matrix
- 13.6 Attachment 6 – Vendor Risk Assessment Summary
- 13.7 Attachment 7 – Vendor Inventory Template

## 14 RECORD RETENTION

- 14.1 Record retention is consistent with the PPL Corporation Records Management Retention Schedules.
- 14.2 Records supporting this procedure include:
- 14.2.1 Deny List
  - 14.2.2 Pre-Approved List
  - 14.2.3 Tiering Questionnaire Form
  - 14.2.4 Software Contracts Without Negotiable Terms Questionnaire
  - 14.2.5 Third-Party Assessment
  - 14.2.6 VRQ or equivalent

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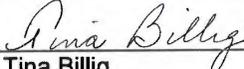
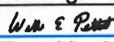
- 14.2.7 Vendor Risk Mitigation Matrix
- 14.2.8 Tracking of Mitigation Activities
- 14.2.9 Vendor Risk Assessment Summary
- 14.2.10 Vendor Inventory Template Form
- 14.2.11 Any records on litigation hold must be retained until instructed otherwise.

## 15 PROCESS CONTROLS

- 15.1 Contingency Vendors identified and assessed – preventive control.
- 15.2 Corporate Card policy specifically references not to use corporate card for items not on the Pre-Approved list and to check the Deny List prior to purchase. – preventive control.
- 15.3 Higher level approvals required if the Business Line decides to accept the risk against the recommendation of the review process – procedural control.
- 15.4 Identification of risk mitigation activities to reduce risk – preventive control.
- 15.5 Inability to enter a purchase request for a Vendor on the Deny List – preventive control.
- 15.6 Interim assessment considered when specific events occur – procedural control.
- 15.7 NTAP review prior to risk assessment process – preventive control.
- 15.8 NTAP holds implementation of any new software until notification of successful completion of risk assessment or contract completion– preventive control.
- 15.9 Process to check Expelled status in Asset Suite against the Deny List – procedural control.
- 15.10 The Cyber Security Testing process requires a sign off from the owner of this process to ensure that new Vendors or Vendors for new devices for NERC CIP Cyber Assets are appropriately cyber risk assessed prior to completion of approval to use – preventive control.
- 15.11 Tier assignment verification for scope changes and correct tier assignment prior to Vendor approval – preventive control.
- 15.12 Weekly report reviewed by Supply Chain to identify Vendors with a change in tier assignment – detective control.
- 15.13 With addition to Deny List, check for existing engagements – procedural control.
- 15.14 With a new requisition for an existing Vendor, Supply Chain reviews the tier assignment and timing of last assessment for compliance – procedural control.

## 16 REVISION HISTORY

 PPL Electric Utilities	<b>EU-NERC-CIP-013</b> <b>PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan</b>	Custom ID: <b>EU-NERC-CIP-013</b> Revision: 2 Effective Date: 12/17/2020 Page 24 of 37
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<b>Prepared by:</b>	
	Tina Billig Senior IT Security Specialist – Cybersecurity
	
	Kathrine Carreiro Associate IT Security Specialist – Cybersecurity
<b>Reviewed by:</b>	
	Preston Walker Manager – Reliability Assurance
	
	William Pettit Director – Supply
	
	Chris Randle Director – Cyber Security
<b>Approved by:</b>	
	Matthew B. Green Chief Information Officer
	
	David J. Bonenberger VP - Transmission and Substations PPL EU NERC CIP Senior Manager

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Revision	Date	Revision Comments
0	06/15/2020	1. Initial Release.
1	10/01/2020	1. Section 6.1.4 – Updated by separating tier levels. 2. Section 6.5.1. – Updated with reference to use of Corporate card for Pre-Approved items. 3. Section 7.3.4 – Added details for when the team review results in a negative recommendation and the Business Line does not want to proceed. 4. Section 7.3.4.4 – Updated Approval matrix for situations when the Business Line wants to proceed with a Vendor after the Team Review recommendation was a “no” to include all Business Line VP’s using or planning to use the Vendor. 5. Section 15 – Added preventive control around corporate card use. 6. Section 9 - Added CP 605, EU-NERC-CIP-020 and EU-NERC-CIP-030 as references. 7. Attachment 3 – Updated Tiering Questionnaire Form. 8. Attachment 5 - Updated Risk Mitigation Matrix Template. 9. Attachment 6 - Updated Vendor Risk Assessment Summary Form. 10. Attachment 7 – Updated Vendor Inventory Template.

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2	12/17/2020	<ol style="list-style-type: none"> <li>1. Clarified throughout the application of this process for sharing of Confidential or higher classified information without a procurement contract.</li> <li>2. Updated Tier 2 timeframe from 6/30/21 to 6/30/22 to align with date in ESS-07.</li> <li>3. Added Section 6.9 related to Country of Origin.</li> <li>4. Modified 7.2.5.4 and 7.3.5.4.5 to remove the Risk Mitigation Matrix as a requirement for Software without Negotiable Terms.</li> <li>5. Updated 7.3.2 (and various other places) to reflect Tier 3 assessments as optional and the follow-on section to indicate no assessment for Tier 4 and 5.</li> <li>6. Added language in 7.4.2.1 to clarify that renewals or additional agreements within the assessment period (1 year for Tier 1 and 3 years for Tier 2) do not require a technical assessment.</li> <li>7. Added ESS-07, Third Party Cybersecurity Risk Management as a reference.</li> <li>8. Added CST control in the form of cyber risk assessment sign off in 15.10.</li> <li>9. Updated Attachments 1 thru 5 with changes resulting from the alignment to ESS-07 and other tweaks.</li> </ol>
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### **Attachment 1 – Vendor Tier Categories\***

#### **Tier 1:**

All Vendors that meet one or more of the following:

1. Vendors of: NERC CIP Cyber Assets (hardware, software); vendors of services related to those assets; or
2. Vendors that provide programmable products (hardware and/or software), or services utilized in Industrial Control Systems (“ICS”) environments that are relied upon for operations of critical systems where failure to provide the contracted product or services would likely cause a disruption to one or more critical business processes. ; or
3. Vendors that have administrator access to ICS systems that are deemed as critical for delivery of critical business operations or adherence to regulations as determined by PPL.

Critical systems/processes are those that could cause significant negative impact to PPL even if the disruption lasted less than 24 hours.

#### **Tier 2:**

All Vendors not meeting Tier 1 criteria that meet one or more of the following:

1. Vendors that provide programmable products (hardware and/or software), or services utilized in Information Technology (“IT”) environments that are relied upon for operations of essential systems where failure to provide the contracted product or services would likely cause a disruption to one or more essential business processes; or
2. Vendors that have administrator access to IT systems that are deemed as essential for delivery of essential business operations or adherence to regulations as determined by PPL; or
3. Vendors that have been provided electronic files or have means of electronic/digital access, either direct or remote, to Restricted information or systems that process Restricted information, except where those services are exclusively delivered utilizing PPL owned and managed computing assets; or
4. Vendors that provide programmable products (hardware and/or software), or services utilized in ICS environments that are relied upon for operations of important systems where failure to provide the contracted product or services would likely cause a disruption to one or more important business processes; or
5. Vendors that have administrator access to ICS systems that are deemed important for delivery of business operations or adherence to regulations as determined by PPL.

Essential systems/processes are those that could cause significant negative impact to PPL if the disruption lasted less than 24 hours.

Important systems/processes are those that could cause a medium negative impact to PPL if the disruption lasted from 1 to 3 days.

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**Tier 3:**

All Vendors with a contract not meeting the above criteria that meet one of the following:

1. **Managed Service Providers (“MSP”); or**
2. Vendors that have administrator access to ICS systems that do not meet the criteria in Tier 1 or Tier 2; or
3. Vendors that have been provided electronic files or have means of electronic/digital access, either direct or remote, to Confidential information or systems that process Confidential information, except where those services are exclusively delivered utilizing PPL owned and managed computing assets; or
4. Vendors that have administrator access to IT systems that do not meet the criteria in Tier 2.

**Tier 4:**

All Vendors with a contract not meeting the above criteria that meet one of the following:

1. **Cloud Service Providers (“CSP”); or**
2. Vendors that have been provided electronic files or have means of electronic/digital access, either direct or remote, to Business Use information or systems that process Business Use information; or
3. Vendors that provide staff augmentation services where those services are exclusively delivered utilizing PPL owned and managed computing assets
4. All other Vendors that provide programmable hardware, software or services utilized in IT or ICS environments.

**Tier 5:**

All Vendors not included in one of the Tiers above.

1. These Vendors provide products or services that are deemed to not involve a level of cyber risk to warrant a detailed cyber assessment.

\*Software contracts without negotiable terms are not tiered. See Section 7.2.5.

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## Attachment 2 – Requirements by Tier

### Tier 1:

1. Insurance: Require cybersecurity insurance coverage commensurate with the risk and value of the contract.
2. Incident Response Plan: Establish and maintain the ability to engage the Vendor to assist during PPL incident response activities including maintaining contact information for the appropriate parties for the Vendor.
3. Incident Notification and Coordination: Vendors notify predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract and coordinates a response as necessary.
4. Security Vulnerabilities: Vendors either notify predefined contacts or make equivalent information publicly available in a timeframe deemed appropriate by PPL of any security vulnerabilities in products or services in scope of the contract.
5. Access: Require notification of predefined contacts when Vendor representatives who have PPL controlled access to computer systems or data, remote or onsite, no longer require access. This process also addresses technical controls for remote access connections.
6. Controls Coordination: For NERC CIP Cyber Asset Vendors, coordinate controls with Vendor regarding any vendor-initiated Interactive Remote Access and system-to-system remote access.
7. Background Checks: Require the Vendor to conduct background checks on employees and contractors that may interact with PPL data or systems. These checks can be completed by the Vendor or PPL. However, PPL performs the background checks for any Vendor that requires NERC CIP Clearance.
8. Patch Validation: Verification of software integrity and authenticity of all software and patches provided by the Vendor is required for NERC CIP Cyber Asset Vendors, evaluate on a per contract basis if patch validation prior to application of any updates provided by the Vendor is required for all others.
9. Evaluate Cybersecurity position: Conduct a review of the cybersecurity controls in place at the third party prior to signing the contract and at each contract renewal. See Section 7.4.2 for more information if a renewal or new contract engagement for an existing Vendor falls inside the annual timing cycle.

### Other considerations:

10. Third-Party Assessment or Equivalent: Request the Vendor to have their security programs reviewed by an independent third party (e.g. SOC2 Type 2.) or equivalent at an agreed upon frequency and review the reports. If the Vendor is a Value-Added Reseller, they may be requested to provide a Third-Party assessment from the 4<sup>th</sup> party (original manufacturer or service provider). Reports can be summaries so long as enough detail is available to understand the effectiveness of the cybersecurity program. If the Vendor is going to assess a fee for the completion of the 3<sup>rd</sup> party assessment, it is up to the members of the cyber risk assessment process to determine if the fee is reasonable given the potential risk posed by the Vendor. Software Vendors are not subject to this consideration since the SOC2 report is less

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valuable as an assessment tool.

11. Cybersecurity Monitoring: Consider obtaining an initial view and then ongoing monitoring the security posture of Vendors via a commercially available cybersecurity monitoring service. Use the results provided by this service to inform PPL of specific cybersecurity risks and respond to the risks identified as PPL deems appropriate. Note that Vendors may not be available for monitoring.
12. Insider Risk: Consider if the Vendor has an insider risk program.
13. Country of Origin:
  - 13.1. When purchasing hardware, request the Vendor disclose the country or countries where hardware components are designed, manufactured, and assembled.
  - 13.2. When purchasing software, request the Vendor disclose the country or countries where the software was developed or supported.
  - 13.3. Compare the responses above to the Countries of Origin list for consideration on the viability of the Vendor as well as any other controls that may be appropriate to implement if use, or continued use is considered.
14. Ownership: To the extent possible, determine ownership structure of the Vendor and use this information as a factor in overall risk posed by the Vendor. Request notification when a change in ownership occurs.
15. Privacy: Evaluate on a per contract basis the need to implement both contractual and technical controls to protect data in accordance with PPL privacy policies and procedures.

**Tier 2:**

1. Insurance: Require cybersecurity insurance coverage commensurate with the risk and value of the contract.
2. Incident Notification: Vendor notifies predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract.
3. Security Vulnerabilities: Vendors either notify predefined contacts or make equivalent information publicly available in a timeframe deemed appropriate by PPL of any security vulnerabilities in products or services in scope of the contract.
4. Access: Require requiring notification of predefined contacts when Vendor representatives who have PPL controlled access to computer systems or data, remote or onsite, no longer require access. This process also addresses technical controls for remote access connections.
5. Evaluate Cybersecurity position: Conduct a review of the cybersecurity controls in place at the third party prior to signing the contract. See Section 7.4.2 for more information if a renewal or new contract engagement for an existing Vendor fall within the 3 year assessment cycle.

**Other Considerations:**

6. Incident Response Plan: As appropriate for the engagement, establish and maintain the ability to engage the Vendor to assist during incident response activities including maintaining contact information for the appropriate parties for the Vendor.
7. Third-Party Assessment or equivalent: If applicable, request the Vendor to have their security programs reviewed by an independent third party (e.g. SOC2 Type 2.) or equivalent at a

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frequency of a minimum of three years and review the reports at least every three years.

Reports can be summaries so long as enough detail is available to understand the effectiveness of the cybersecurity program.

8. Background Checks: Evaluate on a per contract basis requiring the Vendor to conduct background checks on employees and contractors that may interact with PPL data or systems. These checks can be completed by the Vendor or PPL.
9. Country of Origin:
  - 9.1. When purchasing hardware, request the Vendor disclose the country or countries where hardware components are designed, manufactured, and assembled.
  - 9.2. When purchasing software, request the Vendor disclose the country or countries where the software was developed or supported.
  - 9.3. Compare the responses above to the Countries of Origin list for consideration on the viability of the Vendor as well as any other controls that may be appropriate to implement if use, or continued use is considered.
10. Insider Risk: Evaluate on a per contract basis evaluating if the Vendor has an insider risk program.
11. Privacy: Evaluate on a per contract basis the need to implement both contractual and technical controls to protect data in accordance with PPL privacy policies and procedures.

**Tier 3:**

**Other Considerations:**

1. Insurance: Evaluate cybersecurity insurance coverage commensurate with the risk and value of the contract.
2. Incident Notification: Based on the nature of the engagement, consider a requirement for Vendor to notify predefined contacts of any security event or incident that impacts or could impact products or services utilized under the contract.
3. Access: As appropriate, establish a process requiring notification of predefined contacts when Vendor representatives who have access to computer systems or data, remote or onsite, no longer require access. This process also addresses technical controls for remote access connections.
4. Background Checks: Evaluate on a per contract basis requiring background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the Vendor or by PPL.
5. Country of Origin:
  - 5.1. When purchasing hardware, request the Vendor disclose the country or countries where hardware components are designed, manufactured, and assembled.
  - 5.2. When purchasing software, request the Vendor disclose the country or countries where the software was developed or supported.
6. Third-Party Assessment or Equivalent: Evaluate on a per contract basis the need to request the third party to have their security programs reviewed by an independent third party (e.g. SOC2 Type 2) or equivalent at a minimum of every three years and review the reports at least every three years. Reports can be summaries so long as enough detail is available to understand the

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effectiveness of the cybersecurity program.

7. Evaluate Cybersecurity position: On a per contract basis, evaluate the need for a review of the cybersecurity controls in place at the third party prior to signing the contract.

**Tier 4:**

**Other Considerations:**

1. Background Checks: Evaluate on a per contract basis requiring background checks on individuals that may interact with subsidiary data or systems. These checks can be completed by the Vendor or by PPL.
2. Country of Origin:
  - 2.1. When purchasing hardware, request the Vendor disclose the country or countries where hardware components are designed, manufactured, and assembled.
  - 2.2. When purchasing software, request the Vendor disclose the country or countries where the software was developed or supported.
3. Insurance: For services, consider insurance coverage commensurate with the risk and value of the contract.
4. Access: For services, physical access control as required in accordance with CP 208 and GP 309.

**Tier 5 and Pre-Approved List:**

**Other Considerations:**

1. Insurance: For services, consider insurance coverage commensurate with the risk and value of the contract.
2. Access: For services, physical access control as required in accordance with CP 208 and GP 309.

Inability to support the requirements listed above for all tiers, must be documented as follows:

- When logging the contract in the Vendor Inventory Template identify areas where the contract did not meet the requirements.
- The list of contracts that do not meet the minimum requirements is reviewed by the PPL EU Security Council at least annually commencing after July 1, 2021.

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### Attachment 3 – Tiering Questionnaire Form

**TIERING QUESTIONNAIRE**

Date:

Name of person filling out this form:

Vendor Name (if not designated, enter TBD):

Tiering

**Tier 5**

Vendor URL:

Description of requisition/summary of scope of work (be as detailed as possible - what does the software do; what hardware, make/model of hardware or name of software) :

**Tier Evaluation**

Populate the Y/N column per your application/Vendor (Additional clarification may be found on the Guidance tab for some questions)

Y/N

Comments

**General for ALL**

1. Is the programmable HW or SW part of a NERC CIP Cyber Asset and/or for services (for cyber impacting items like programming, developing/updating settings, firmware/software updates, testing and IP configurations) on a NERC CIP Cyber Asset?***		
PPL data/information or systems that process such data? RESPOND below to the highest level of information they get access to/create/store. (See CP 404 for additional details)		
3. Is the information classified as Restricted (ex. BCS), PII, PHI, merger acquisition or insider financial information)?		
4. Is the information classified as Confidential (ex. CVI, CEII, CII, trade secrets, legal info, non-public contracts, strategy and business plan info,		
5. Is the information classified as Business Use (ex. work procedures/policies, information available for use by Vendors but not for general		
6. Is the Requisition for cyber impacting services/programmable hardware/software used in a PPL Industrial Control System (ICS)?		
7. Will the Vendor have System Administrative Rights to PPL Systems (hardware and/or software) in an ICS environment?		
8. Is the Requisition for cyber impacting services/programmable hardware/software used in PPL's Information Technology (IT) environment?		
9. Will the Vendor have System Administrative Rights to PPL Systems (hardware and/or software) in an IT environment?		

**Criticality**

10. Is the Requisition for services/hardware/software for a Business Process, System or Asset whereby lack of availability for 24 hrs or less would cause significant negative impact to PPL		
11. Is the Requisition for services/hardware/software for a Business Process, System or Asset whereby lack of availability for 1-3 days would cause meaningful/medium negative impact to PPL		

**Services**

12. Is the Requisition for a service provided by a third-party?		
13. Is the Requisition for a Cloud Service Provider (CSP) (Includes Software as a Service (SAAS), Platform as a Service (PAAS) and Infrastructure as a Service (IAAS))		
14. Is the Requisition for a Managed Service Provider (MSP) to provide a third-party service?		
15. Is the Requisition for a staff augmentation?		
16. Are PPL laptops provided to the Vendor for use in providing services?		
17. Are the PPL laptops the exclusive means for access to information/systems?		

**Hardware**

18. Is the Requisition for Hardware (HW)? (Anything physical)		
19. Does the Vendor have direct or remote electronic access to PPL hardware?		
20. Is access for set-up only? (a "N" response would imply the need for ongoing access)		
21. Is the hardware programmable? (Does it include software/firmware?)		

**Software**

22. Is the Requisition for Software (Including applications and cloud computing) (SW)?**		Need NTAP ticket #
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**Attachment 4 – Software Contracts Without Negotiable Terms Questionnaire Form**

Name/Version \_\_\_\_\_  
Submitted by: \_\_\_\_\_ Date of Submission: \_\_\_\_\_  
NTAP # \_\_\_\_\_

- 1.0 What function does the software provide? \_\_\_\_\_  
\_\_\_\_\_
- 2.0 Is this software intended to be utilized in our CIP environment? (Y/N) \_\_\_\_\_
- 3.0 Could someone access this software via an Internet connection? (Y/N) \_\_\_\_\_
- 4.0 What are the inputs to the software? \_\_\_\_\_
- 5.0 What are the outputs of the software? \_\_\_\_\_
- 6.0 Can this software be reached via the network? Can it reach the network?  
\_\_\_\_\_
- 7.0 Does the software operate as a privileged user? \_\_\_\_\_
- 8.0 What is the deployment plan in terms of usage volume? \_\_\_\_\_
- 9.0 What is the mechanism for getting information related to vulnerabilities and patches?  
\_\_\_\_\_

Additional comments: \_\_\_\_\_  
\_\_\_\_\_

Revision Date: 12/16/20  
Revision # 3

 PPL Electric Utilities	<b>EU-NERC-CIP-013</b> <b>PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan</b>	Custom ID: <b>EU-NERC-CIP-013</b> Revision: 2 Effective Date: 12/17/2020 Page 35 of 37
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### Attachment 5 – Vendor Risk Mitigation Matrix Template

VENDOR RISK MITIGATION MATRIX									
Date of evaluation:									
Vendor Name:									
Vendor Location:									
Description of Hardware, Software or Service under evaluation:									
Vendor Tier									
Owner	Requirement	Tier 1 Required (Y/N)	Tier 2 Required (Y/N)	Vendor Risk Level	Mitigation	Mitigated Risk Level	Mitigation Owner (Vendor or group in PPL)	Plan Date for Completion of Mitigating actions	Comments
Risk Management	Cybersecurity Insurance in context of indemnification/liability caps	Y	Y	Low		Low			
process owner	Incident Response	Y	N	Med		Med			
IT Cybersecurity	Incident Notification	Y	Y	Low		Low			
IT Cybersecurity	Notification of Security Vulnerabilities	Y	Y	Low		Low			
IT Cybersecurity	Process for removal of access/technical controls for remote access	Y	Y	High		High			
IT Cybersecurity	Third-Party Assessment SOC2 Type 2, ISO cert, assessment to NATF criteria	N	N	Med		Med			
IT Cybersecurity	Background Checks	Y	N	Med		Med			
IT Cybersecurity	Country of Origin: HW and SW	N	N	Low		Low			
IT Cybersecurity	Evaluate Cybersecurity Position (VRQ, SIG, other assessment tool)	Y	Y	Low		Low			
IT Cybersecurity	Cybersecurity monitoring	Y		High		High			
OGC	Privacy: Contractual and technical controls to protect data	N	N	Low		Low			
IT Cybersecurity	Patch Validation (software only)	Y*		Low		Low			
OGC	License agreement concerns (software only)			Low		Low			
others as needed									
* required for NERC CIP Vendors - a consideration for all other Vendors  Y indicates a Tier requirement N indicates it is a consideration blank indicates that it is not a consideration or a requirement									
Last revised:		15-Dec-20							
Revision #:		3							

 PPL Electric Utilities	<b>EU-NERC-CIP-013</b> <b>PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan</b>	Custom ID: <b>EU-NERC-CIP-013</b> Revision: 2 Effective Date: 12/17/2020 Page 36 of 37
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**Attachment 6 – Vendor Risk Assessment Summary Form**

**[Max 2 pages in addition to the Vendor Risk Mitigation Matrix]** [All areas highlighted in red should be replaced with supporting project Information per topic, if applicable. Not all topics will apply to every proposal. In some cases, this level of detail may not be required because these discussions were previously held in choosing the solution/Vendor. When completed, the template should not have any remaining sections in red. Technical or other related documents should be referenced and included as attachments, not incorporated into the text of this document.]

**Date for Approval:** \_\_\_\_\_ **Requestor:** \_\_\_\_\_  
**Vendor/Product:** \_\_\_\_\_ **Vendor Tier/Reason for Tier:** \_\_\_\_\_  
**Business Unit/Line of Business:** \_\_\_\_\_ **Vendor Risk Mitigation Matrix Date:** \_\_\_\_\_  
**Participants in risk assessment:** \_\_\_\_\_

**Project Description**

- **Project Scope and Timeline [ a couple of sentences]**  
[List and explain the scope of goods and/or services provided by this Proposal and timeline.] [Is the technology proven/appropriate?]
- **Background [a couple of sentences]**  
[Explain background and why the Solution is being proposed.]
- **Significant risks are listed on the Vendor Risk Mitigation Matrix. Refer to the appropriately dated and versioned matrix as referenced above.**  
[Any necessary commentary to the information on the Vendor Risk Mitigation Matrix]
- **Other Alternatives Considered (1–Recommendation, 2–Do nothing, 3 –Next Best Alt)**  
[List and discuss other potential alternatives to completing the project. Explain why alternatives other than the proposed option should not be considered.]
- **Assumptions**  
[List major assumptions.]
- **Impacts to Business Continuity**  
[Documented exit strategy]

**Conclusions and Business Recommendation (delete whichever option below does not apply)**

It is recommended that [Vendor Name] be approved for tiered work as proposed by accepting the residual risk as identified above and per the information on the Vendor Risk Mitigation Matrix and any other attached information.  
The result of the cyber assessment was to not recommend [Vendor Name] for tiered work as presented. However, the Business Line is willing to override this recommendation and to accept the residual risks and concerns as identified above and per the information on the Vendor Risk Mitigation Matrix and any other attached information.

**Signatures of Approvers:**

Signature/Title: \_\_\_\_\_  
Signature/Title: \_\_\_\_\_

Additional signatory lines can be added to accommodate additional required signatures.

Revised: September 28, 2020  
Revision: 2

 PPL Electric Utilities	<b>EU-NERC-CIP-013</b> <b>PPL Electric Utilities Cyber Security Supply Chain Risk Management Plan</b>	Custom ID: <b>EU-NERC-CIP-013</b> Revision: 2 Effective Date: 12/17/2020 Page 37 of 37
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**Attachment 7 –Vendor Inventory Template**

Vendor Organizational Information							
NERC CIP Cyber Asset Vendor	Vendor Name	Vendor Website	Vendor Location	Vendor Cybersecurity Support Contact Information	Vendor Business Contact Information	Last Approval Date	
Expire Date of the Contract	Product or Service Description	Tier Level or Open Source/Free SW	PPL EU Business Line Information	PPL EU Business Contact Information	SC Contact	Tier Requirement Deviation	Deny List Exception

# EU-NERC-CIP-013 Rev 2 Final

Final Audit Report

2020-12-21

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By:	TLBillig@pplweb.com
Status:	Signed
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Division 2-57

Request:

Please provide the basis for Mr. Dudkin's statement (at 35:1-2) that PPL Electric Utilities has greater capacity and ability to interconnect solar generation than most electric utilities.

Response:

Most electric utilities today use distributed energy resource (DER) nameplate ratings to determine hosting capacity and, if required, determine system upgrades. However, PPL Electric Utility Corporation's ("PPL Electric") can perform a more precise analysis by using PPL Electric's DER management devices installed locally. The DER management devices provide greater visibility of inverter-based DERs' actual output, yielding a more precise analysis and thereby resulting in an increase of hosting capacity and a more accurate system assessment for upgrades. As a result, PPL Electric anticipates that more customers will be able to interconnect DERs without triggering additional capital investments.

Additionally, with PPL Electric's first-of-its-kind ability to monitor and actively manage inverter-based DERs, PPL Electric anticipates that the amount of DERs that can be safely and reliably interconnected with PPL Electric's electric distribution system can be significantly increased, as demonstrated in various industry research studies (*see footnotes below*) and in PPL Electric's internal studies. Under PPL Electric's DER Management Pilot Program, smart inverters are equipped with Volt/VAR curves, which can increase the amount of DERs that can interconnect to the system before making costly system investments. For each section of a circuit where a DER may interconnect, PPL Electric evaluates specific criteria, including loading, voltage and protection, and their associated limits, for possible negative system impacts. For residential solar systems, one of the common criterion violated is overvoltage. Typically, this is due to a combination of comparably high solar generation output and low demand (especially during spring and autumn months). Inverter-based DERs equipped with Volt/VAR can autonomously absorb reactive power during these times, which effectively lowers the voltage and avoids overvoltage conditions. As a result, more inverter-based DERs can be hosted on that distribution circuit without overvoltage violations.

*See* Seuss, J., *et al.*, "Improving Distribution Network PV Hosting Capacity via Smart Inverter Reactive Power Support" (July 2015), available at <https://energy.sandia.gov/download/33230/>.

*See* Ding, F., *et al.*, "Technologies to Increase PV Hosting Capacity in Distribution Feeders" (July 2016), available at <https://www.nrel.gov/docs/fy16osti/65995.pdf>.

Division 2-58

Request:

Mr. Dudkin states (at 13:18-20) that the transition to renewable energy resources will require different grid capabilities and data management systems. Please:

- a. Provide a detailed list of these grid capabilities and data management systems that PPL believes will be needed on the Narragansett system;
- b. Explain in detail how PPL will transition its capabilities and data management systems to integrate those already implemented by National Grid; and
- c. Provide a list of National Grid's grid capabilities and data management systems which will need to be abandoned or replaced in order to achieve integration with the PPL systems.

Response:

a. The electric distribution system is currently designed for the one-way flow of power. To transition to an environment that allows for a significant amount of renewable energy resources, the electric distribution system will need to be converted to have better insight into, and management of, the power flows that are coming onto the system from renewable energy resources. PPL has not performed a detailed analysis of the specific grid capabilities and data management systems that will be needed on the Narragansett system to transition to the clean energy future envisioned in Rhode Island. However, as set forth in detail in PPL and PPL RI's response to data request Division 1-35, PPL Electric Utilities Corporation ("PPL Electric") has implemented numerous advanced grid capabilities and data management systems that it believes are necessary to transition to a cleaner energy future.

b. PPL has not performed a detailed analysis of the capabilities already implemented by National Grid that will be integrated into the Narragansett electric distribution system ultimately operated by PPL.

c. PPL has not performed a detailed analysis of National Grid's grid capabilities and data management systems that will need to be abandoned or replaced in order to achieve integration with the PPL electric system. Therefore, no specific determinations on abandonment or replacement have been made as of this time.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY  
Docket No. D-21-09  
PPL Corporation and PPL Rhode Island Holdings, LLC's  
Responses to Division's Second Set of Data Requests  
Issued on June 11, 2021

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Division 2-59

Request:

Please provide a list of each innovation implemented by PPL as discussed on page 9, lines 19 and 20 of Mr. Dudkin's testimony.

Response:

PPL and PPL RI refer to their responses to data requests Division 1-35, Division 2-8, Division 2-14, and Division 2-47.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY  
Docket No. D-21-09  
PPL Corporation and PPL Rhode Island Holdings, LLC's  
Responses to Division's Second Set of Data Requests  
Issued on June 11, 2021

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Division 2-60

Request:

Please provide five years of detailed system reliability statistics for each PPL jurisdiction including comparisons to the Institute of Electrical and Electronics Engineers (IEEE) statistics following the IEEE standards for reliability. This should include SAIDI, SAIFI and CAIDI.

Response:

PPL Electric Utilities Corporation IEEE SAIFI, SAIDI, and CAIDI statistics are listed below:

<b>Year</b>	<b>IEEE SAIFI</b>	<b>IEEE SAIDI</b>	<b>IEEE CAIDI</b>
2016	0.698	71.1	102.0
2017	0.604	70.0	116.1
2018	0.736	82.5	112.1
2019	0.661	74.3	112.5
2020	0.689	68.6	99.6

Louisville Gas & Electric Company, Kentucky Utilities Company, and Old Dominion Power Company's IEEE SAIFI, SAIDI, and CAIDI statistics are listed below:

<b>Year</b>	<b>IEEE SAIFI</b>	<b>IEEE SAIDI</b>	<b>IEEE CAIDI</b>
2016	1.041	100.47	96.5
2017	0.839	75.41	89.9
2018	0.923	95.24	103.2
2019	1.056	93.59	88.6
2020	0.741	69.74	94.1

Division 2-61

Request:

Referencing the Petition at paragraph 32, PPL states it has a culture of safety. Please provide:

- a. For the past five years, the number of personal injury events that occurred on PPL system in each of the following categories: public; employee; contractor employee and any other applicable category not specified here; and
- b. For the past five years, the number of property damage events in each of the following categories: vehicular; private property, company property, and any other applicable category not specified here.

Response:

- a. The previous five-year injury count for employees, contractors, and the public for the Pennsylvania-based PPL companies <sup>(1)</sup> is provided in the table below:

	2016	2017	2018	2019	2020
Employee <sup>(2)</sup>	52	34	27	31	46
Contractor <sup>(3)</sup>	11	15	21	26	19
Public <sup>(4)</sup>	20	9	16	14	8

- (1) PPL Electric Utilities Corporation ("PPL Electric"), PPL EU Services Corporation, and PPL Services Corporation.
- (2) OSHA Recordable Injuries & Illnesses.
- (3) OSHA Recordable Injuries & Illnesses. Includes Transmission, Substation, Distribution, and Vegetation contractors.
- (4) Public injuries and fatalities, excluding PPL employees and PPL contractors, reported by PPL Electric and submitted to the Pennsylvania PUC for the five-year period of 2016-2020. Please also see Attachment PPL-DIV 2-62-1.

The previous five-year injury count for employees, contractors, and the public for Louisville Gas & Electric Corporation ("LG&E") and Kentucky Utilities Corporation ("KU") is provided in the table below:

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
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	2016	2017	2018	2019	2020
Employee (5)	29	29	40	35	35
Contractor (6)	66	74	67	76	48
Public (7)	1	2	2	3	2

(5) OSHA Recordable Injuries (excluding illnesses).

(6) OSHA Recordable Injuries (excluding illnesses).

(7) Public incidents that were reported to the Kentucky Public Service Commission by LG&E and KU.

- b. The previous five-year vehicle incident for the Pennsylvania-based PPL companies is provided in the tables below:

Edison Electric Institute ("EEI") Recordable<sup>(8)</sup> Motor Vehicle Incident

	2016	2017	2018	2019	2020
Public Roadway Incident	68	49	57	53	37
Off-Public Roadway Incident	32	14	29	17	15

(8) EEI Recordable – Any occurrence involving a motor vehicle which results in death, injury, or property damage, unless such vehicle sustained conditions not in the EEI Non-Recordable definition.

EEI NON-Recordable<sup>(9)</sup> Motor Vehicle Event

	2016	2017	2018	2019	2020
Public Roadway Incident	39	53	68	32	25
Off-Public Roadway Incident	16	7	16	5	10

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
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(9) EEI Non-Recordable – The following types of events are not EEI Recordable motor vehicle incidents:

- Damage to a Company Fleet Vehicle or personal vehicle used for company business solely caused by stone chips, flying birds, or contact with live animals.
- Damaged Company Fleet vehicles or personal vehicles that are properly parked.
- Normal wear and tear of vehicle components.
- Mechanical failures.
- Flat tires.
- Minor bumper dings and dents.

The previous five-year vehicle incident for LG&E and KU is provided in the tables below:

	2016	2017	2018	2019	2020
Controllable Motor vehicle incident	62	50	57	45	40
Non-controllable Motor vehicle incidents	43	36	48	52	54

Pennsylvania based PPL companies' property damage incidents are listed in the table below:

	2016	2017	2018	2019	2020
Company Property	2,043	2,118	2,114	2,044	1,889
Private Property	60	51	64	29	3

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
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LG&E and KU have had 5,683 aggregate property damage incidents related to private property over the past 5 years.

LG&E and KU have had 8,397 aggregate property damage incidents relating to situation where third parties have damaged company property over the past 5 years.