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# Small Hydropower Interconnections: Analysis of Interconnection Processes

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# 1.0 Introduction

Small hydropower projects have faced the challenge of navigating the process to interconnect their generation source to electricity distribution and transmission grids. Small hydropower developers have found interconnection procedures to be opaque and ultimately result in unexpected cost surprises and long timelines.

Noting these challenges, the U.S. Department of Energy Water Power Technologies Office enlisted Pacific Northwest National Laboratory (PNNL) and Oak Ridge National Laboratory (ORNL) to investigate the small hydropower interconnection landscape across the United States. After reviewing the status of small hydropower (“Small Hydropower Interconnections: Small Hydropower in the United States”) and the interconnection procedures across the United States (“Small Hydropower Interconnections: State Interconnection Processes”) in the first two white papers of this series, this paper uses recent data from small hydropower interconnection applications to benchmark the efficacy of the process. Using data from interconnection queues hosted by utilities, balancing authorities, independent system operators (ISOs), and regional transmission organizations (RTOs), this paper provides context for the costs, timelines, and types of upgrades required for small hydropower projects.

Interconnection applications and study reports for small hydropower projects were analyzed to collect key pieces of information about the interconnection process, timeline, costs, and type of upgrades required for interconnection. Information sourced from the reports was entered into an Interconnection Benchmarking database (IBdb), which may be found in Appendix A.1. Information from this database was used to evaluate the performance and challenges associated with interconnecting small hydropower projects. This white paper presents a description of the sources contained in the interconnection database (Section 0), an analysis of the interconnection timeline (Section 3.0), an evaluation the cost of interconnection upgrades (Section 4.0), and a description of the types of infrastructure upgrades (Section 5.0).

The final paper in this series (“Small Hydropower Interconnections: Best Practices”) will use the analysis described here to outline best practices for interconnection processes that will help overcome barriers to future small hydropower development.

# 2.0 Interconnection Database

Information about past or current interconnection requests was found through either interconnection queues or interconnection study reports made available from a transmission or distribution owner. Interconnection queues provide basic information about the interconnection request, including the application date, project status, processing timeline, nameplate capacity, and point of interconnection (POI) voltage. Interconnection study reports include more detailed information about the interconnection request, including upgrades required to meet safety standards, proposed construction timeline, and associated costs. Although, they are not always made publicly available, interconnection study reports provide a richer source of information than the interconnection queue to understand the interconnection constraints and upgrade requirements.

Interconnection queues and study reports were sourced from utilities, independent system operators (ISO), and balancing authorities (BA). Not all of these entities provide interconnection information to the public, so many different authorities were searched to identify as much information about small hydropower interconnection applications as possible. Ultimately, 38 utilities and 6 ISO/BAs were identified that posted interconnection queues, and 10 utilities and 3 ISO/BAs provided access to interconnection study reports for multiple small hydropower projects (Table 1). Many of the study reports were available in the public domain, such as through the OATI webSmartOASIS[1] portal, but some study reports were accessed through a non-disclosure agreement or through a request for information to interconnection queue owners.

Table 1. Sources of Interconnection Benchmarking Database

| | # of Utilities | # of ISOs/BAs |
|---|---|---|
| Searched for reports from | 50+ | 10+ |
| Interconnection queues posted by | 38 | 6 |
| Interconnection reports posted by | 14 | 4 |
| Multiple small hydro studies available | 10 | 3 |

The interconnection queues and study report archives were reviewed to identify hydropower projects less than 20 MW nameplate capacity. Information from these projects was transcribed into the IBdb for analysis. Through 17 different queue authorities, 290 small hydropower projects were found in interconnection queues and 151 interconnection reports for small hydropower projects were made available (Table 2).

[1] The portal is accessed at https://www.oasis.oati.com/#.

Table 2. Project versus Studies Breakdown by Queue Authority

| Queue Authority | Number of Small Hydropower Projects in Interconnection Queue | Number of Small Hydropower Projects with Interconnection Study Reports |
|---|---|---|
| BPA | 1 | 1 |
| Central Hudson | 6 | 0 |
| Central Maine Power | 2 | 0 |
| IPC | 83 | 20 |
| ISO-NE | 21 | 6 |
| MISO | 2 | 1 |
| NSTAR | 1 | 0 |
| NYISO | 6 | 3 |
| NYSEG RG&E | 7 | 4 |
| National Grid | 37 | 17 |
| Northwestern Energy | 5 | 5 |
| Orange Rockland | 2 | 0 |
| PJM | 54 | 46 |
| PacifiCorp | 50 | 43 |
| Southwest Power Pool | 4 | 2 |
| WAPA | 3 | 1 |
| WMECO | 6 | 2 |
| Total | 290 | 151 |

The variety of different projects included in the IBdb is described in this section. Additional statistics about the composition of the database can be found in 0.

## 2.1 Project Status

The pathway for a project to become interconnected starts with an interconnection application, which leads to an interconnection study. If the interconnection customer (the proposed project) wants to proceed after the study, they enter into an interconnection agreement (IA) with the distribution and transmission operator. After the IA is signed, the interconnection upgrades are implemented as needed and the project becomes operational.

The majority of projects in the database are currently in service, meaning that the interconnection was approved, implemented, and is now in operation (Figure 1). Withdrawn projects comprised another substantial portion of the database. Withdrawn projects were those that applied for interconnection, but for various reasons pulled out of the process and did not execute an IA. The remaining projects either had their interconnection studies in process or signed an IA but the project was not yet in operation.

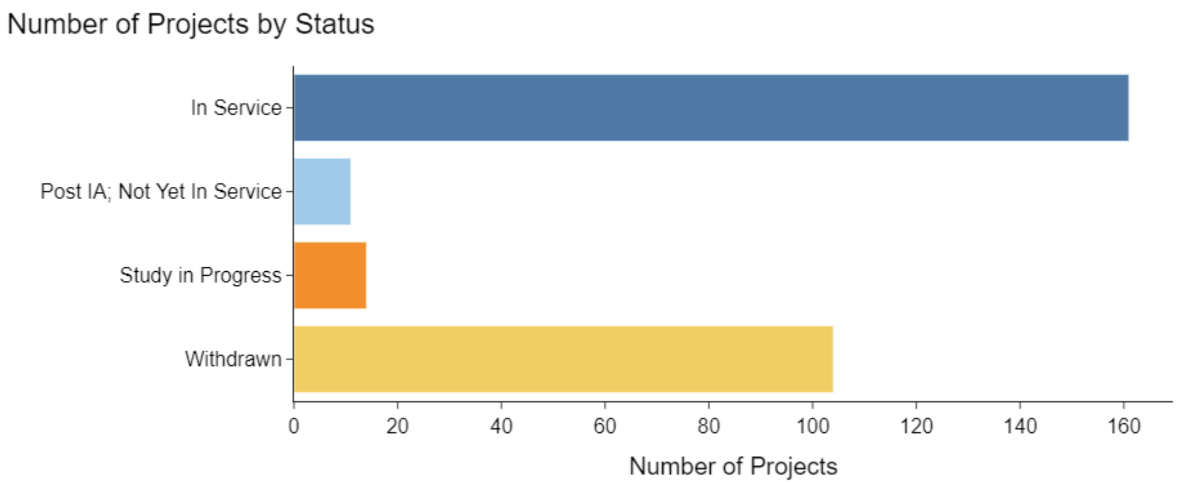



Figure 1. Status of Projects in the IBdb

## 2.2 Capacity

Small hydropower projects that were seeking interconnection at the distribution level were clustered primarily below 5 MW nameplate capacity (Figure 2), as expected based on the analysis of the small hydropower industry ("Small Hydropower Interconnections: Small Hydropower in the United States"). Interconnection studies were available for most projects, but less than half of projects below 2.5 MW had interconnection studies available, which may skew some of the analysis towards projects above 2.5 MW.

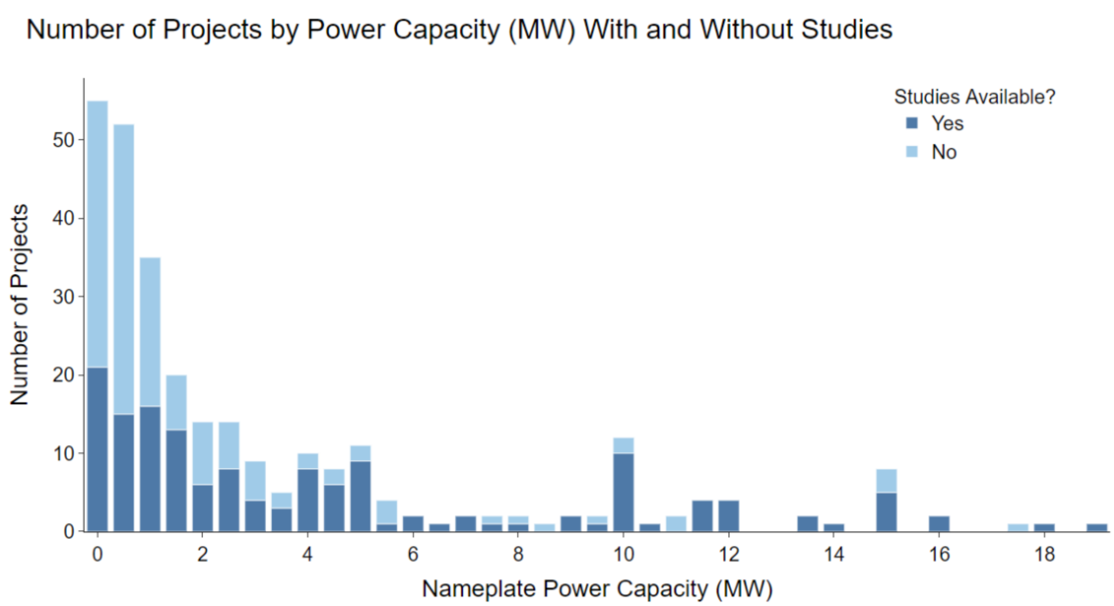



Figure 2. Capacity Histogram Indicating Subset of Projects for which Studies were Sourced

## 2.3 Queue Owner

The database is sourced from a mixture of ISO and utility queues. The queue owner was tracked as the source of information instead of the interconnection authority, as some of the ISO queues hosted distribution scale interconnection reports. A large portion of the projects (29%) originated from Idaho Power Company (IPC) (Figure 3).

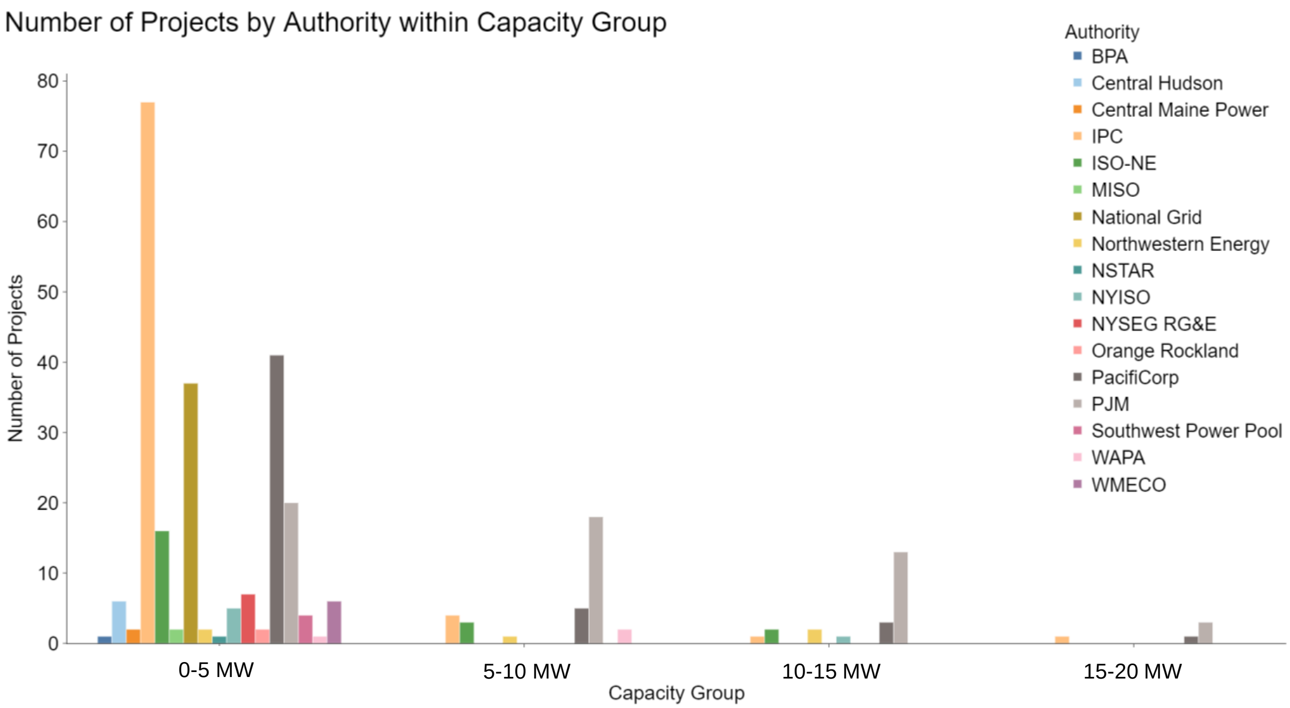
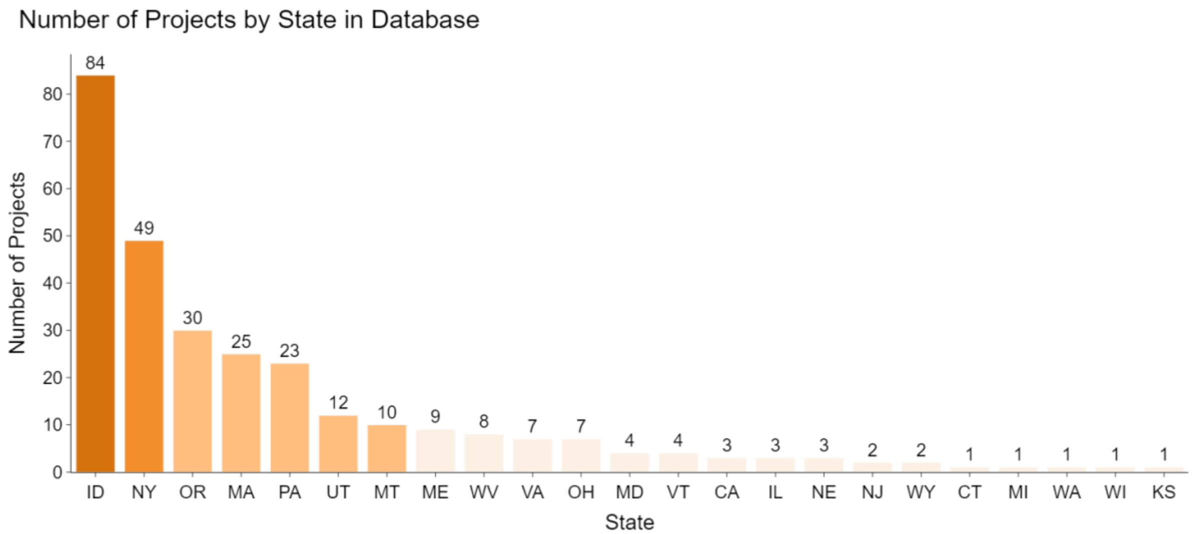



Figure 3. IBdb Capacity Distribution for Queue Owners

## 2.4 Location

Project location spread across the United States, with the most project located in Idaho and New York (Figure 4). However, significant gaps exist in the southeast U.S. and Texas, where the taxonomy indicated small hydropower development activity, but publicly available queues were not found. Regional aggregates per state indicate strong coverage in the Pacific Northwest, the Northeast, and the East (Table 3).



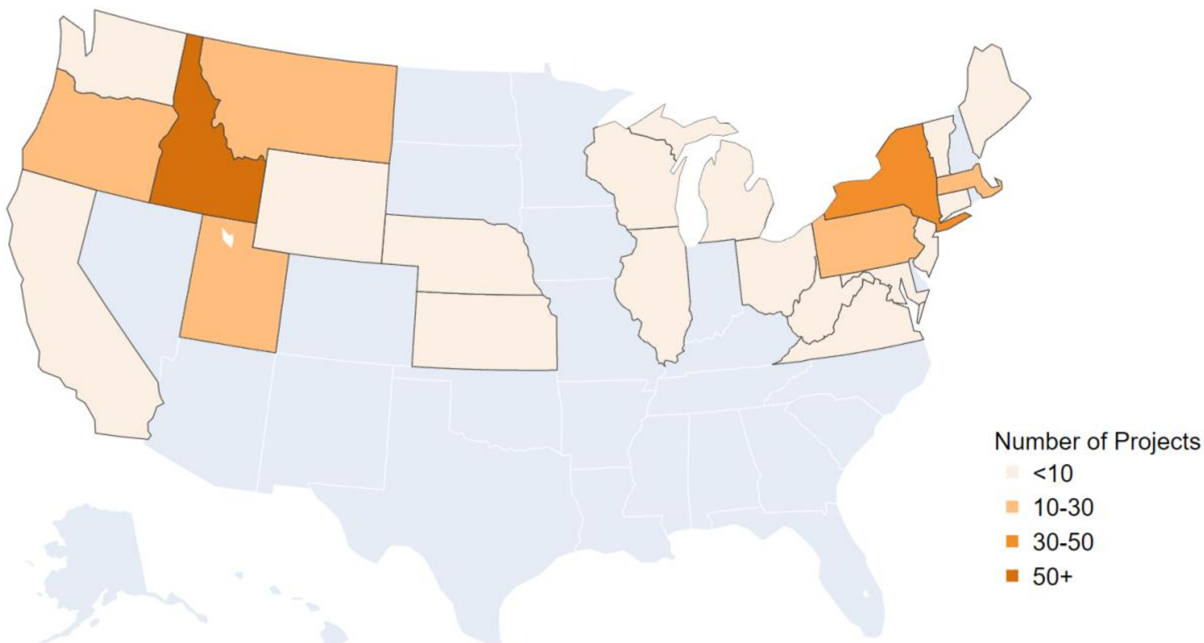




Figure 4. Number of Projects by State in IBdb

Table 3. Regional Organization of States and Number of Projects

| Region | Projects in Region | State | Projects in State |
|---|---|---|---|
| East | 44 | MD | 4 |
| | | NJ | 2 |
| | | PA | 23 |
| | | VA | 7 |
| | | WV | 8 |
| Midwest | 16 | IL | 3 |
| | | KS | 1 |

| Region | Projects in Region | State | Projects in State |
|---|---|---|---|
| | | MI | 1 |
| | | NE | 3 |
| | | OH | 7 |
| | | WI | 1 |
| Northeast | 88 | CT | 1 |
| | | MA | 25 |
| | | ME | 9 |
| | | NY | 49 |
| | | VT | 4 |
| Pacific Northwest | 126 | ID | 83 |
| | | MT | 10 |
| | | OR | 30 |
| | | WA | 1 |
| | | WY | 2 |
| West | 15 | CA | 3 |
| | | UT | 12 |

# 3.0 Interconnection Timeline

The interconnection process includes a study led by the queue owner (the studies may include Fast Track, feasibility, system impacts, and/or facilities study), execution of an IA, and any construction required before the commercial operation date. Across all the small hydropower studies reviewed, the median duration between the application submission and a Fast Track and feasibility studies report was less than 6 months (Figure 5). The median system impacts study and facilities study took between 6 to 7 months after submitting the application. An IA was commonly executed 12 months after submitting the applications, and the median commercial operation date (COD) proposed by the transmission and distribution authority is 20 months after submission. Timeline breakdowns by region and for new generation projects versus facility upgrades and in-service versus withdrawn projects are provided in Appendix B.

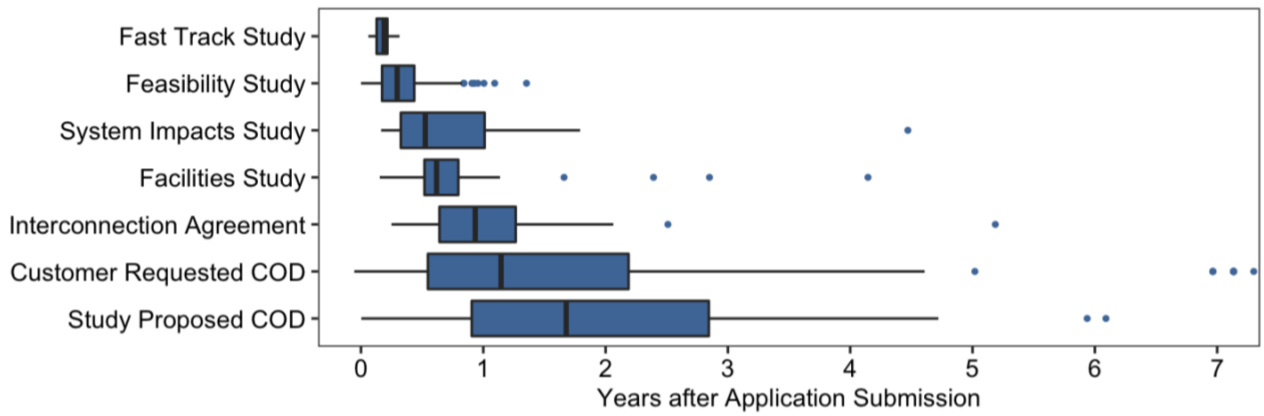



Figure 5. Timeline between Application Submission and Interconnection Milestones for All Projects

The customer requested COD had a wide range of dates, which reflected the developer's desired COD rather than the authority's proposed COD. The customer's expectations were compared with the study's proposed COD, which shows the authority's expected timeline for commercial operation. The difference between these two CODs indicates if the project meets or exceed the customers expectation (Figure 6).

Importantly, the study proposed COD was about a year longer at the median for projects that were withdrawn compared to projects that are ultimately built. This delay may influence a developer's interest to pursue the project. However, the delayed COD was often associated with significant construction activity and high interconnection costs. These factors may have equal or greater influence on the decision compared to a 12-month delay.

In Figure 6, the differences between the customer requested COD and the proposed COD were compared to identify if a delay, when compared to the customer's expectation, influenced whether a project was interconnected. Surprisingly, projects that are in service often had a longer delay between the requested and proposed COD than projects that were withdrawn. These findings indicate that a difference between the customer's expectation and the proposed COD did not influence the decision whether to pursue interconnection or withdraw the project from the queue.

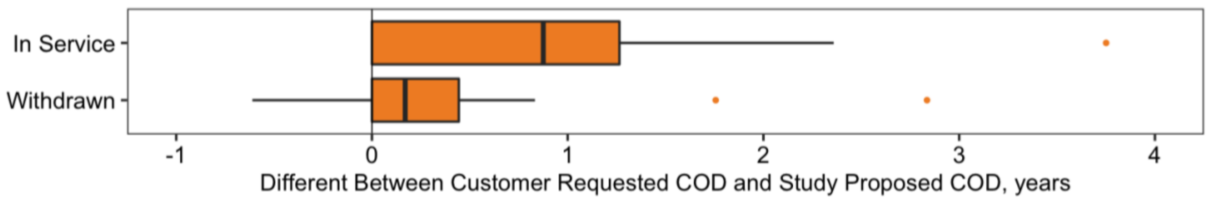



Figure 6. Difference between COD requested by the customer and COD proposed in the interconnection study. Negative values correspond to proposed CODs being sooner than the requested COD.

## 4.0 Interconnection Upgrade Cost and Categorization

Within the full interconnection database, 151 projects described the costs to implement interconnection upgrades. Given that each interconnection application was filed in different years, cost information was adjusted to real 2021 U.S. dollars using the producer price index for the electric power generation industry (FRED, 2021). Projects with costs greater than $30 million were excluded from the analysis as outliers. Table 4 presents the descriptive statistics of the projects with cost data available. Table 5 shows median cost and capacity information on a regional basis.

Table 4. Descriptive Statistics for Projects with Cost Data Available

| Parameter | Final Cost Estimate ($million) [1] | Capacity (MW) [1] |
|---|---|---|
| Mean | 1.08 | 4.47 |
| St. Dev. | 2.92 | 4.76 |
| Min. | 0.00 | 0.0 |
| 25th Percentile | 0.01 | 0.83 |
| Median | 0.20 | 2.45 |
| 75th Percentile | 0.80 | 6.64 |
| Max. | 26.41 | 19.2 |

[1] A data outlier (final cost >$30 million) was removed prior to generating these statistics.

Table 5. Cost and Capacity Data Descriptive Statistics by Region

| Region | Median Upgrade Cost ($Million/MW) | Median Capacity (MW)[1] |
|---|---|---|
| East | $0.095 | 9.90 |
| Midwest | $0.036 | 4.13 |
| Northeast | $0.012 | 1.30 |
| Pacific Northwest | $0.199 | 1.60 |
| West | $0.352 | 1.00 |

[1] Only for projects with cost data available and greater than 0 MW

Figure 7 shows the estimated project cost against the rated capacity of each individual project. The values in the diagram are colored by project status, indicating, among other outcomes, the costs and capacities of projects that were ultimately withdrawn and those that are now in service. The distribution plots along the top of the horizontal and vertical axes show the distribution of each of these status types across both cost and capacity.

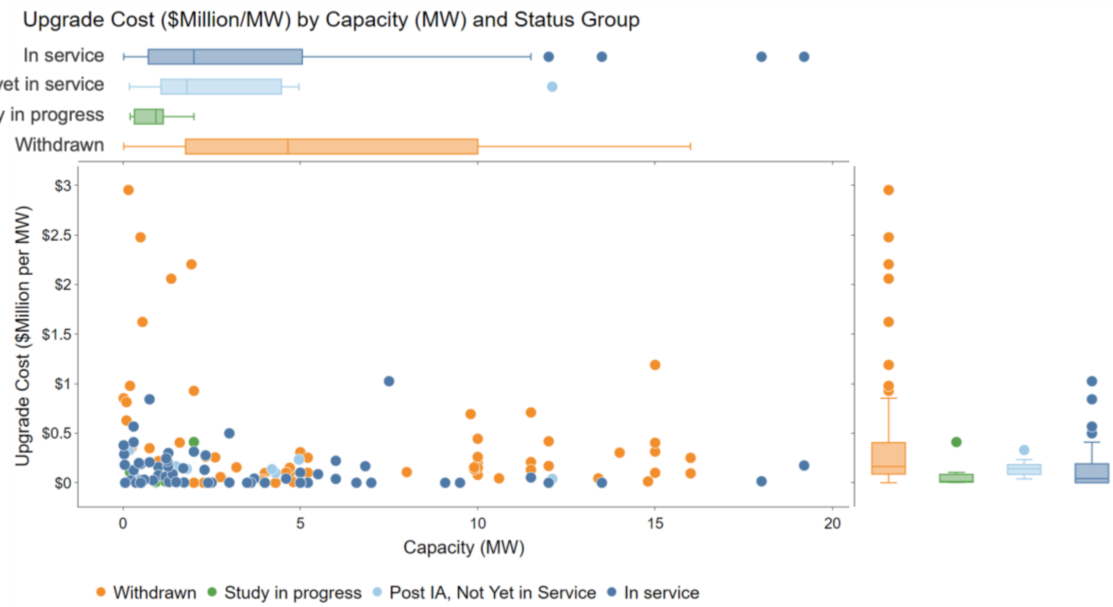



Figure 7. Final Upgrade Cost ($Million/MW) versus Capacity (MW) by Status. Boxplots[1] display distribution per status group by cost (right) and capacity (top)

As indicated by Figure 7, most of the projects were under $0.5 million/MW in total upgrade cost and under 7.5 MW in capacity. Given that most of these projects have smaller capacities (50 percent are under 3.3 MW and 75 percent are under 7 MW), there are less returns to scale on a $/MW basis than would likely be seen with larger MW projects. A clear relationship between project capacity and upgrade cost was not observed as a whole or even within project status types.

The separation by status type in Figure 7 also shows that a high proportion of the larger projects (≥10 MW) and those with higher costs (≥$0.5 million/MW) were ultimately withdrawn. These projects had a higher median cost than those in service, in progress, or still in the study process at the time of data recording. The distribution of withdrawn projects was much wider with regards to capacity than other status categories. In general, not all withdrawn projects had high costs, but most project with the highest costs were withdrawn.

In-service projects, on the other hand, had a tighter distribution around 2 MW, with most projects over 10 MW considered to be outliers. The distribution of in-service projects showed that they predominantly reside in the 1.0–5.0 MW range and were typically under $0.5 million/MW. In general, smaller project were lower cost and had a higher degree of success to come into service.

[1] In the box and whisker plots in this report, the shaded box region represents the 25 percent to 75 percent percentile, with the black vertical line at the median. The horizontal whiskers show the minimum and maximum values not including outliers. The open circles represent outliers, which are classified as being outside the interquartile range by 1.5 times the interquartile range.

# 5.0 Categorization of Interconnection Upgrades

The benchmarking database was grouped into five general categories of the most commonly required system upgrades () that were identified in the interconnection study reports (Table 6). A simplified description of each category is provided below with a technical description available in Appendix C.

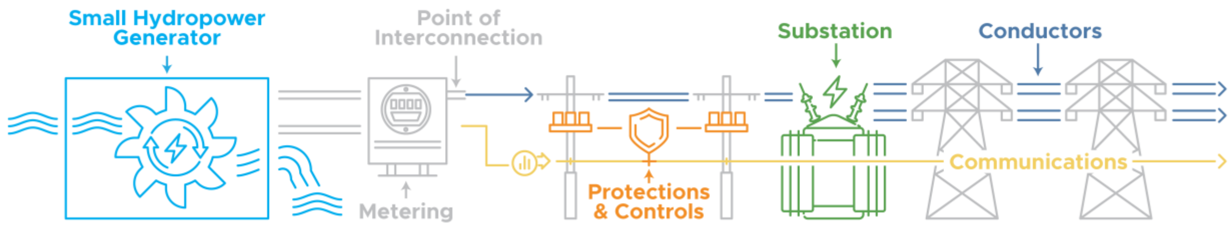



Figure 8. Interconnection upgrade categories

- **Conductoring:** These upgrades relate to electricity conductors spanning between the POI and the affected utility's transmission and distribution facilities.
- **Substation:** Grid interconnections can disrupt the existing system protection and control scheme of the substation, prompting modifications to relay settings, new relays, significant expansions, or new substations altogether.
- **Line Protection and Control (P&C)**: This category involves upgrades to grid protection and control equipment and schemes located outside the boundaries of the substation and interconnection customer's facilities, or in other words, the protection and controls between the interconnection customer's facilities and the affected utility substation(s).
- **Communications:** This category refers to upgrades or additions to systems that allow signals and data to be interchanged between grid system components and control centers. For example, communications systems may facilitate interchange of control signals between grid protection devices or transmit real-time metering data to the serving authority.
- **Metering:** All interconnection customers are typically in business to sell energy to the serving utility or participate in power markets; thus, there needs to be a system that tracks and stores the real-time output of the interconnected generator. Metering refers to all components required to effectively monitor the generator's output.

Significant upgrades were common requirements following an interconnection study, such as expanding existing substations or building new conductors. Other requirements such as metering were also common but are relatively inexpensive and faster to install.

Table 6. System Upgrades and Their Occurrences in the Study Set Grouped by Major Category

| System Category | Sub-category | # of Occurrences |
|---|---|---|
| Conductoring | New Conductors | 23 |
| | Upgrade Existing Conductors | 19 |
| Substation | Expand Existing Substation | 17 |
| | New Substation | 6 |
| | New Relays | 22 |
| | Modify Existing Relay Settings | 16 |
| Line Protection and Control | New Regulator | 3 |
| | New Recloser | 13 |
| | New Line Relays | 15 |
| | Modify Existing Relays | 6 |
| | New Fuses | 2 |
| | Visible disconnect | 1 |
| | Transfer Recloser/Regulator | 1 |
| Communications | Fiber Optic Cable | 9 |
| | Telephonic Connection | 1 |
| | Enable Supervisory Control and Data Acquisition | 11 |
| | Install Direct Transfer Trip Capability at Neighboring Subs/Control Centers | 12 |
| Metering | | 31 |

## 5.1 Required Upgrades by Capacity

Some categories of upgrades were more often requested for higher or lower capacity projects. Figure 9 shows the distribution of different upgrade types requested at different interconnection capacities, which indicates a few trends:

- Reconductoring transmission or distribution lines was requested for projects primarily below 5 MW capacity, while new conductors were requested for projects spanning from 0 to 20 MW.
- New substations were requested for projects that are primarily over 10 MW, which suggests that existing substations may not have over 10 MW of excess capacity.
- Line P&C upgrades were most commonly requested for projects less than 5 MW. This suggests that larger projects may require more significant upgrades that go beyond distribution line P&C modifications.

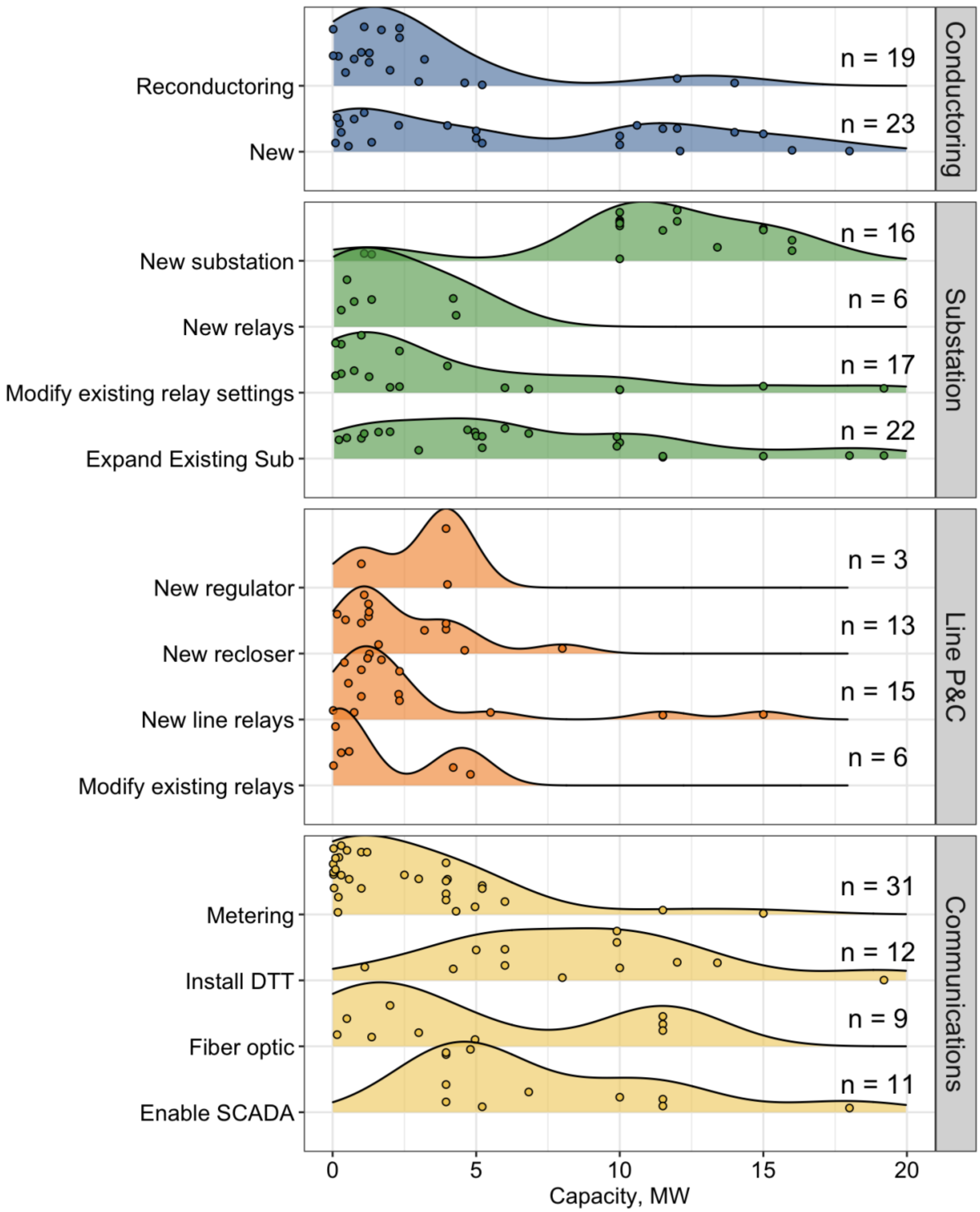



Figure 9. Distribution of Upgrade Requests for Different Project Capacities. The number of projects with cost estimates in each category is shown as the sample size, n, on the right of the chart.

## 5.2 Upgrade Costs by Category

The cost of interconnection varies by type of upgrades that are required (Figure 10).[1] On a cost per nameplate capacity basis, the highest cost upgrades are 1) new substation, 2) new relays at an existing substation, 3) expanding an existing substation, and 4) installing fiber optic communications. The costs for reconductoring are described in depth in 0.

The categorization can be further separated by region (Figure 11) to highlight differences in network upgrade requirements and associated costs across the U.S. Upgrade costs are similar in many categories, but major upgrade categories appear to have higher costs in the Pacific Northwest (PNW). The mean cost of upgrades were higher in the PNW than other regions in the categories of new substation, new line relays, modify existing relays, and new fiber optic communications.

[1] Costs can only be categorized into groups when the cost estimates were itemized in the interconnection study reports. Reports that did not have cost estimates split between

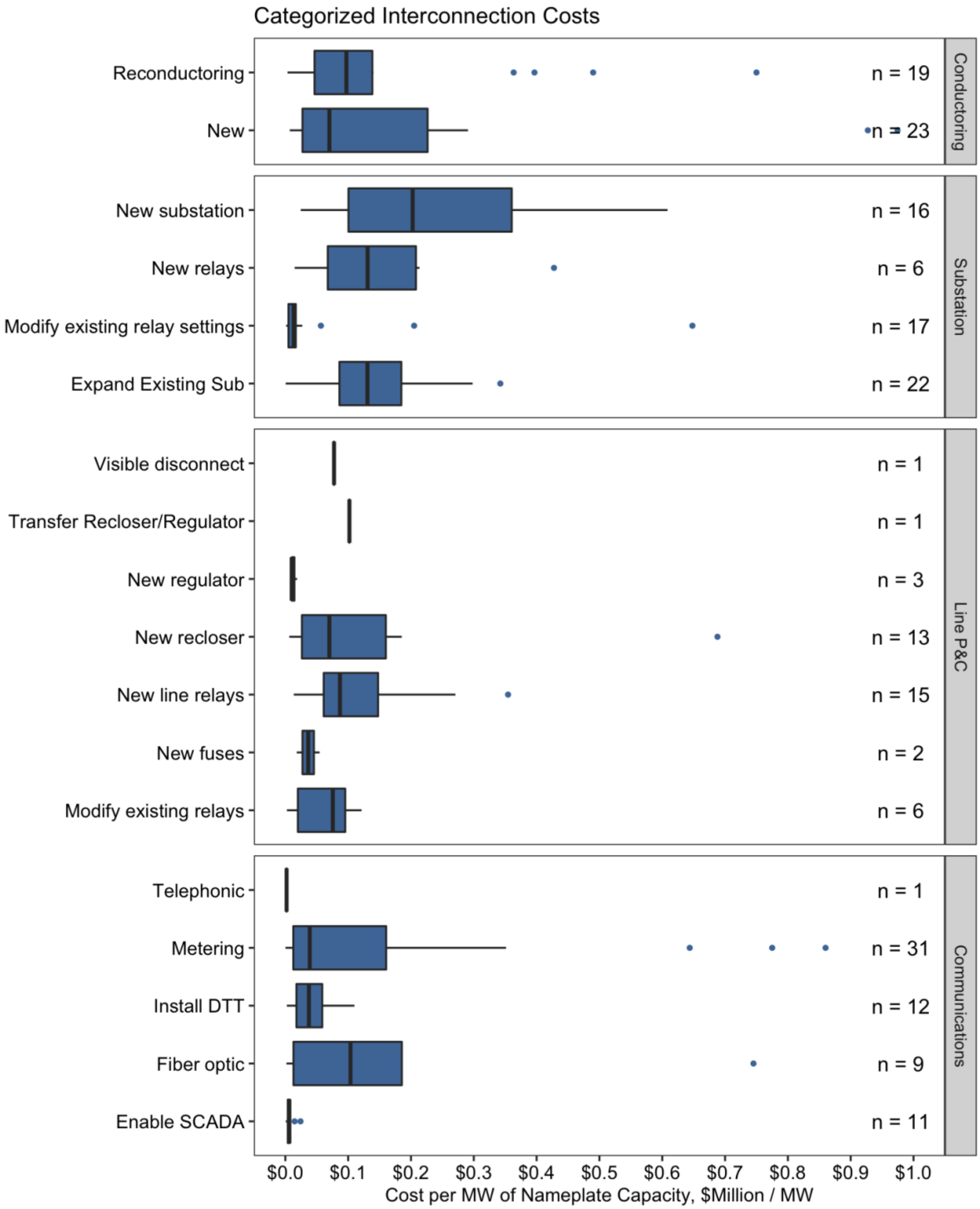



Figure 10. Distribution of Costs Estimates for Each Cost Category. The upgrades are grouped together using the categories shown on the right. The number of projects with cost estimates in each category is shown as the sample size, n, on the right of the chart. Cost estimates are shown in millions of dollars per megawatt, converted to 2021 dollars.

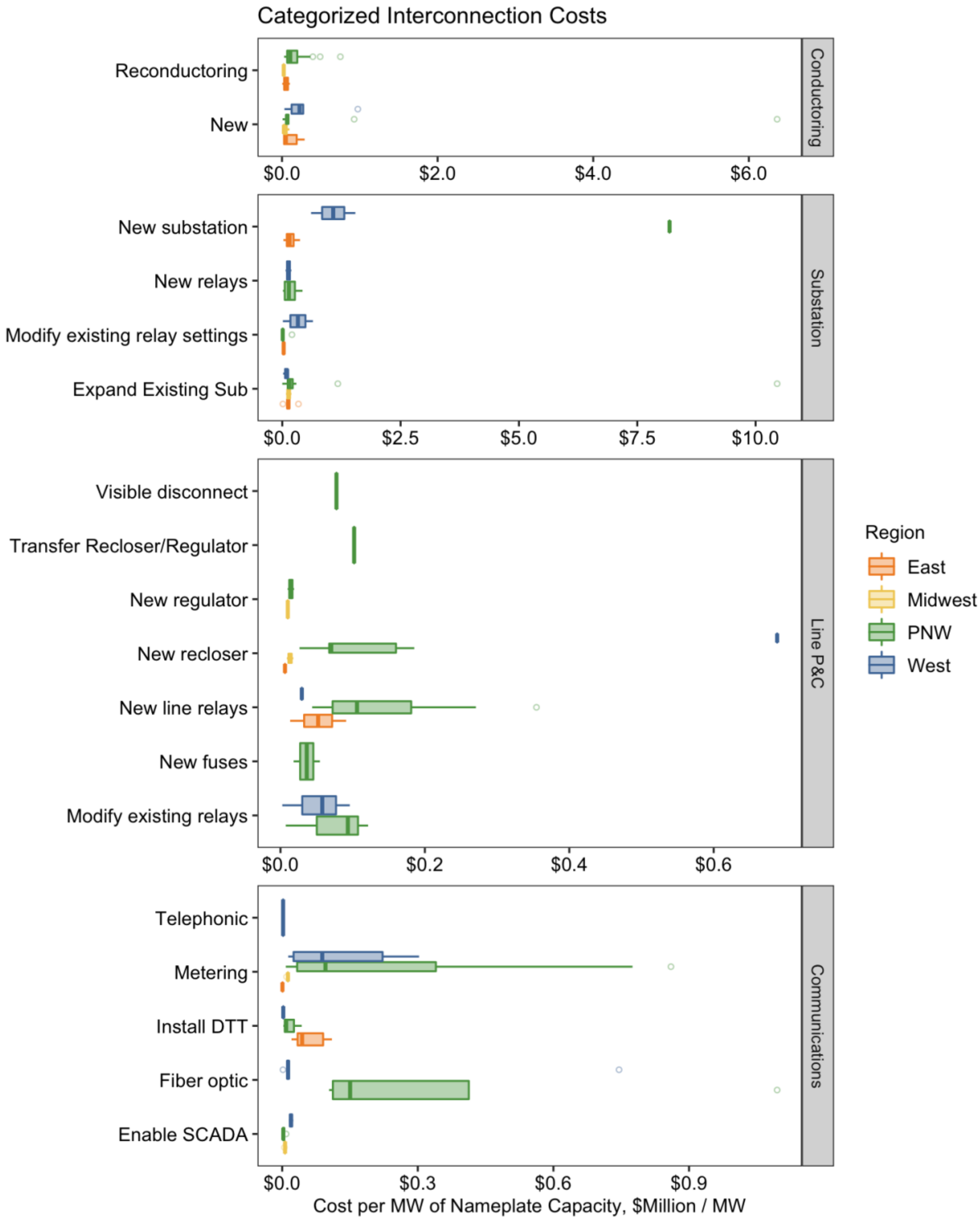



Figure 11. Distribution of Costs Estimates for Each Cost Category Separated by Region. Cost estimates are shown in millions of dollars per megawatt, converted to 2021 dollars. Northeast is not shown on this plot because cost estimates in that region were not provided by component.

# 6.0 Summary

Analyzing interconnection study reports for small hydropower interconnections helps describe the costs, timeline, and requirements for connecting to the electrical grid. The results show that interconnection applications greater than 10 MW or project with interconnection upgrades costs greater than $500,000 per MW were more likely to be withdrawn from the interconnection queue. Most projects that were successfully interconnected were less than 5 MW. The types of upgrades required vary between smaller and larger hydropower projects: smaller projects less than 10 MW often required line P&C upgrades, new relays, and reconductoring; larger projects more often required new substations and new conductors, which can increase costs and complexity of a project. The median time for a project between application and interconnection agreement was approximately 1 year, but the median proposed commercial operation date was longer than the applicant initially expected.

The analysis of interconnection applications helps quantify the interconnection challenges facing the small hydropower industry. The next and final paper in this series describes the best practices for interconnection standards by taking lessons learned from the solar photovoltaic and distributed wind industries (“Small Hydropower Interconnections: Best Practices”).

# 7.0 References

[FRED] Federal Reserve Economic Data. 2021. Producer Price Index by Industry: Electric Power Generation: Utilities. Accessed September 28, 2021 from https://fred.stlouisfed.org/series/PCU2211102211104

# Appendix A – Interconnection Benchmarking Database

This section will further characterize the IBdb by point of interconnection (POI) voltage, distance to POI, region, and project status.

## A.1 Interconnection Benchmarking Database

The IBdb is provided in the embedded spreadsheet file in this subsection. Sources of the data were described in Section 2.0. Starting from these data sources, various project data have been omitted, and other project classifications have been supplemented, such as project status, type, and region, to produce the IBdb. Cost breakdowns by common upgrade type have also been appended for projects where studies could be located and reviewed.

Interconnection_Benchmarking_Datab

## A.2 POI Voltage

POI voltage was tracked carefully based on input from the Technical Advisory Group (TAG) and the inference that high voltages would trigger significant substation and conductoring costs. A large range of POI voltages were encountered, ranging from distribution, to sub-transmission, to medium voltage transmission in scale. However, most projects were found to be below 50 kV, as indicated in Figure A.1, which also indicates the distribution by queue owner.

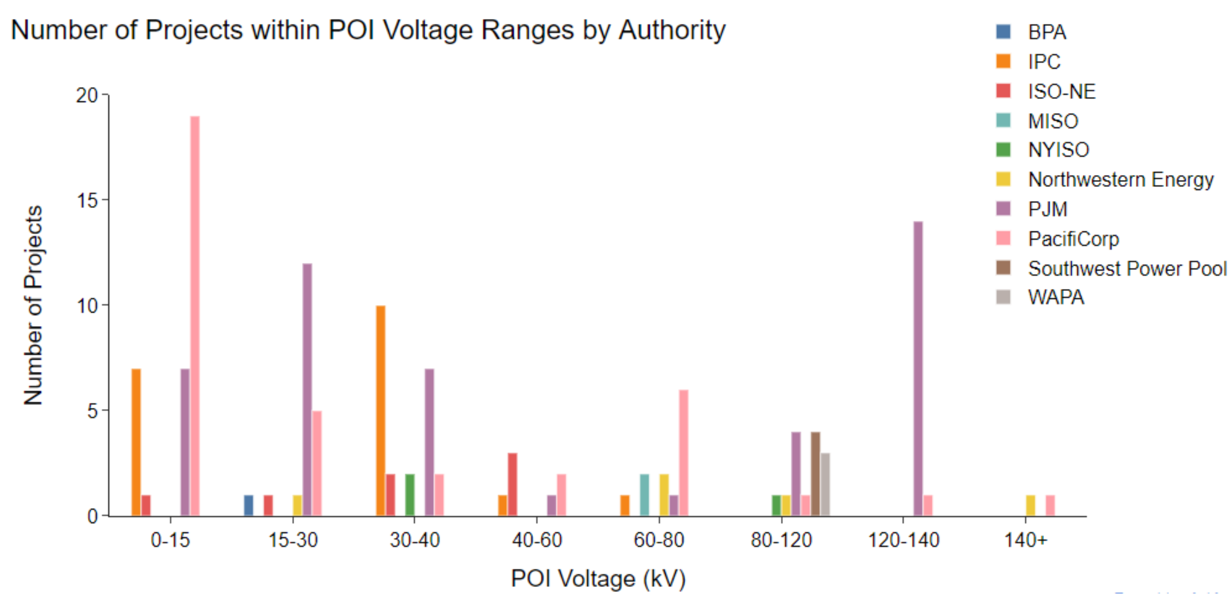



Figure A.1. IBdb Voltage Distribution by Queue Owner

## A.3 Distance to POI

Of the projects reviewed in the compilation of the IBdb, distances to the points of interconnection were mined primarily from one-line diagrams in the studies. Table A.1 provides binning of projects by POI voltage and their minimum, average, and maximum distance to POI, as compiled in the IBdb.

Table A.1. POI Voltage and Distance to POI

| POI Voltage kV | Number of Projects | Average Distance to POI | Maximum Distance to POI | Minimum Distance to POI |
|---|---|---|---|---|
| 7 | 1 | -- | -- | -- |
| 12 | 25 | 1.58 | 3.98 | 0.34 |
| 13 | 1 | -- | -- | -- |
| 21 | 3 | 8.84 | 20.00 | 1.02 |
| 23 | 10 | 1.15 | 2.27 | 0.06 |
| 35 | 13 | 1.11 | 1.11 | 1.11 |
| 44 | 2 | -- | -- | -- |
| 46 | 4 | 2.51 | 4.77 | 0.25 |
| 69 | 13 | 7.75 | 13.90 | 1.00 |
| 100 | 3 | -- | -- | -- |
| 115 | 11 | -- | -- | -- |
| 138 | 15 | 0.96 | 2.50 | 0.10 |
| 161 | 2 | 1.25 | 1.25 | 1.25 |

Successful projects in the database, which are in service today, correspond to longer average distances to the POI than withdrawn projects (Table A.2).

Table A.2. Distance to POI Sorted by Project Status

| Project Status | Average Distance to POI (mi) | Maximum Distance to POI (mi) | Minimum Distance to POI (mi) |
|---|---|---|---|
| Withdrawn | 1.49 | 13.9 | 0.00 |
| In Service | 3.03 | 22.0 | 0.00 |
| Construction in process/IA executed | 4.00 | 20.0 | 0.00 |

## A.4 Final Upgrade Cost ($/MW) vs. Project Type

Figure A.2 demonstrates that applications marked as new generation (as opposed to a license renewal application or an upgrade to an existing system) had higher costs on average. In addition, the variance of costs for new generation plants was higher than that of established projects, with the exception of new generation, post interconnection agreement (IA) projects for which the IBdb lacked sufficient sample size. This demonstrates that established projects likely require fewer larger and more costly upgrades.

In addition, Figure A.2 shows the compound effect of project type and status. Some takeaways from this plot include the following:

- Most projects ultimately withdrawn were for new generation applications.
- New generation projects that were not ultimately withdrawn had lower median costs compared to those that were withdrawn, but the difference is less than expected.
- New generation projects that were not withdrawn still had a higher median cost compared to all types of established projects.

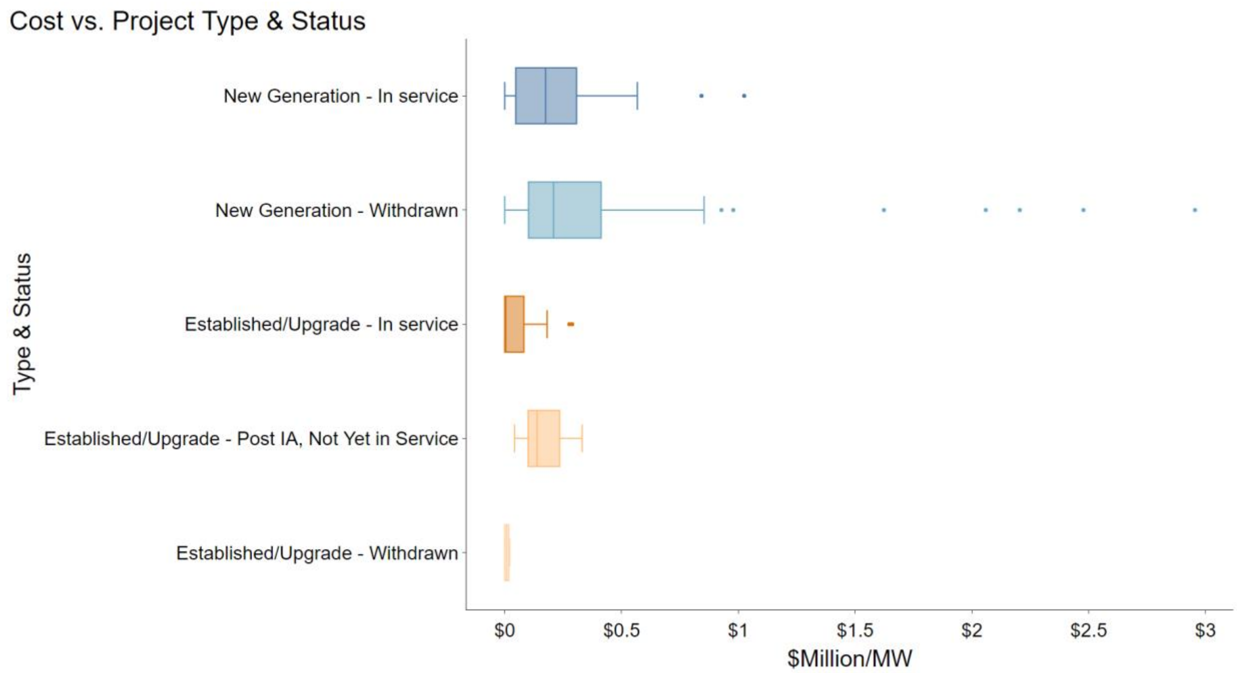



Figure A.2. Boxplots of Project Cost ($Million/MW) by Status and Project Type

## A.5 Project Cost ($/MW) by POI Voltage and Status

Project costs were also reviewed as a function of POI voltage and project status to extract any overall trends. InFigure A.3, overall project cost distributions, normalized by project capacity, are plotted as a function of POI voltage bins. No discernible trend of POI voltage versus costs is observed. However, median cost values do increase sharply above 120 kV. Below 80 kV, there is little variation in median costs.

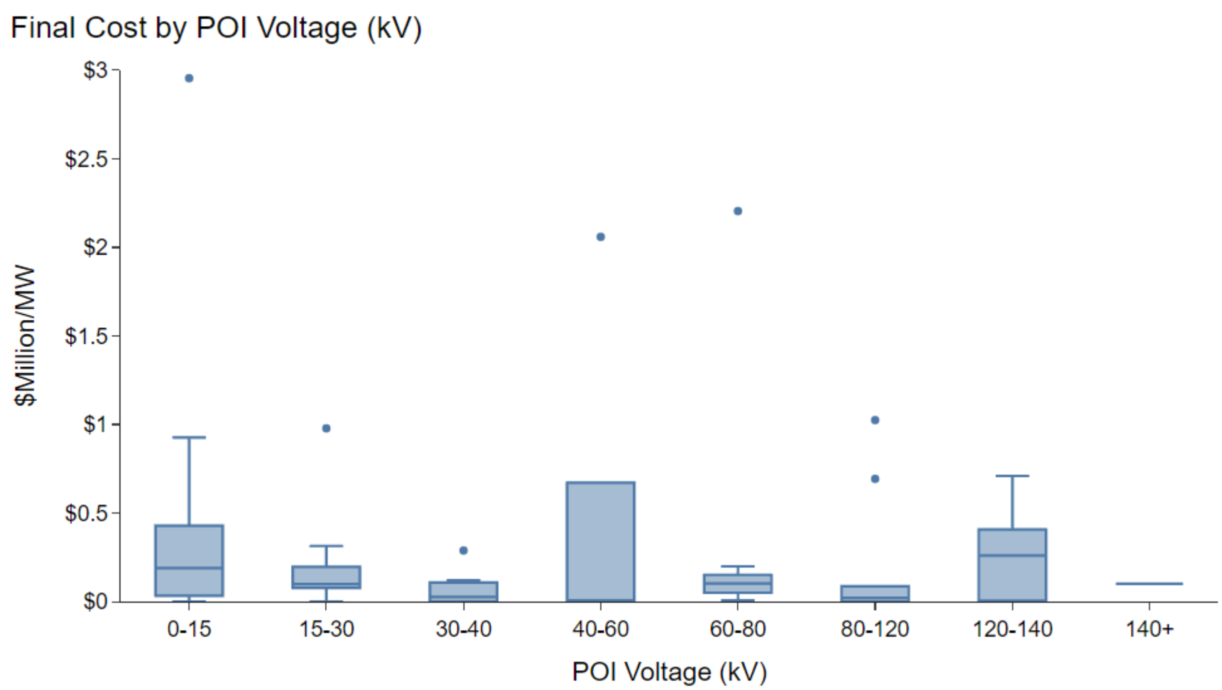



Figure A.3. Cost Distributions as a Function of POI Voltage. Costs are normalized by project capacity and discounted to 2021 dollars.

Table A.3 shows that the cost appears to be higher at higher voltages for new generation projects that were ultimately withdrawn, particularly between 34.5 and 105.0 kV. Overall, this plot suggests that POI voltage level is potentially an influential factor for new generation projects in determining cost.

Table A.3. Median Cost ($Million/MW) by POI Voltage for New Generation Projects Ultimately Withdrawn

| Voltage Bin (kV) | Median Cost ($Million/MW) |
|---|---|
| 12-12.49 | $0.13 |
| 12.49-23 | $0.35 |
| 23-25 | $0.10 |
| 25-34.5 | $0.11 |
| 34.5-69 | $0.70 |
| 69-105 | $0.69 |
| 105-138 | $0.31 |
| 138-161 | $0.10 |

The cost data was analyzed at a state level to identify any trends or patterns at a higher granularity. Figure A.4 below shows data for new and established projects in each state and their corresponding cost in $million/MW. This plot demonstrates the number of projects in each state that had cost information as well as how many of those were for new or established generation. Additionally, this plot shows the previously identified trend that upgrade costs for established projects are typically lower as well as further confirms the presence of the trend at an individual state level.

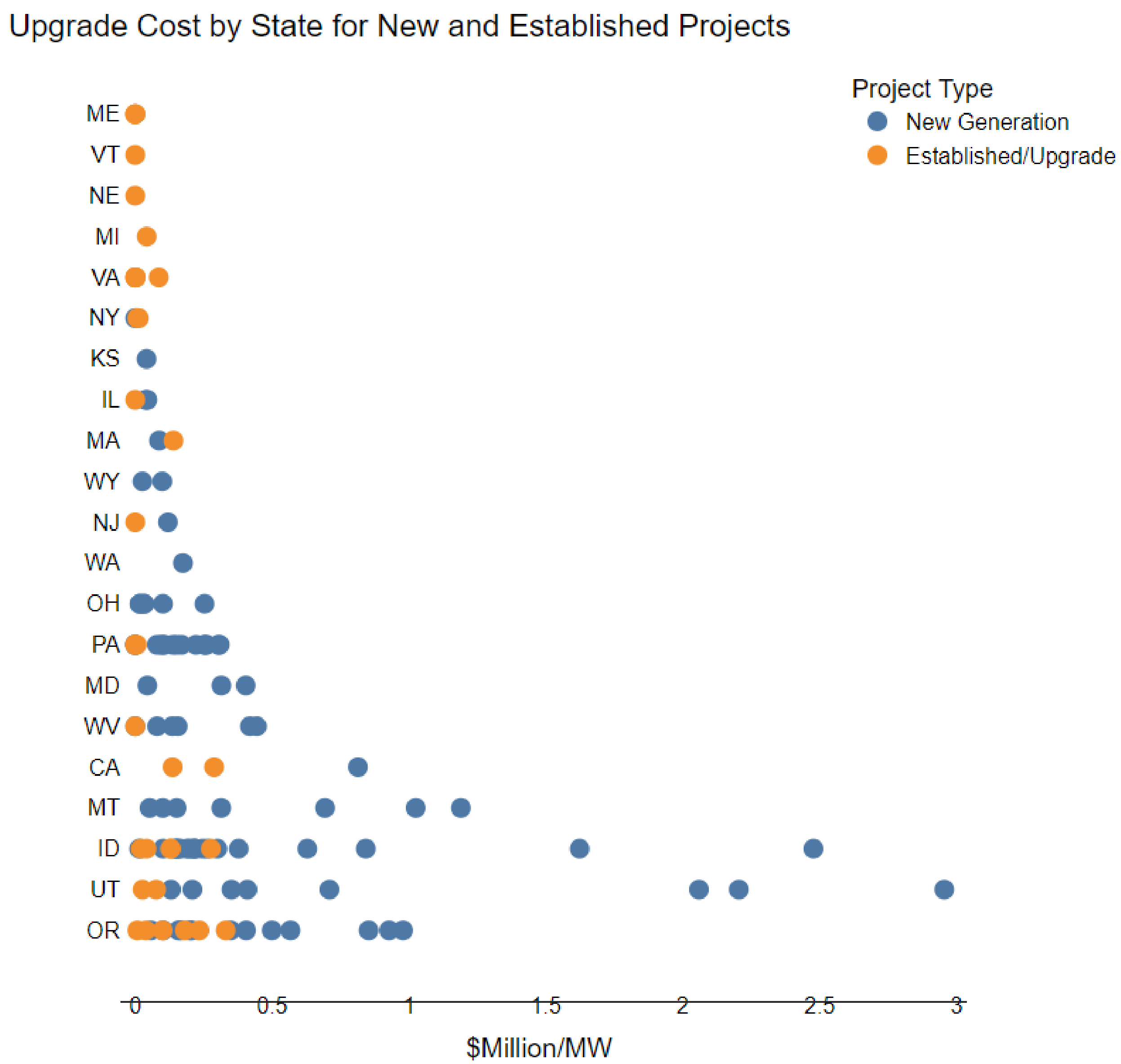



Figure A.4. Cost ($Million/MW) by State and Project Type

# Appendix B – Detailed Timeline Analysis

Interconnection timelines have slight variations based on the region of interconnection (Figure B.1). Applications in the West and Northeast have a median timeline of 1 year between submission and proposed COD, compared to nearly 2 years in the Pacific Northwest and East, and over 2 years in the Midwest.

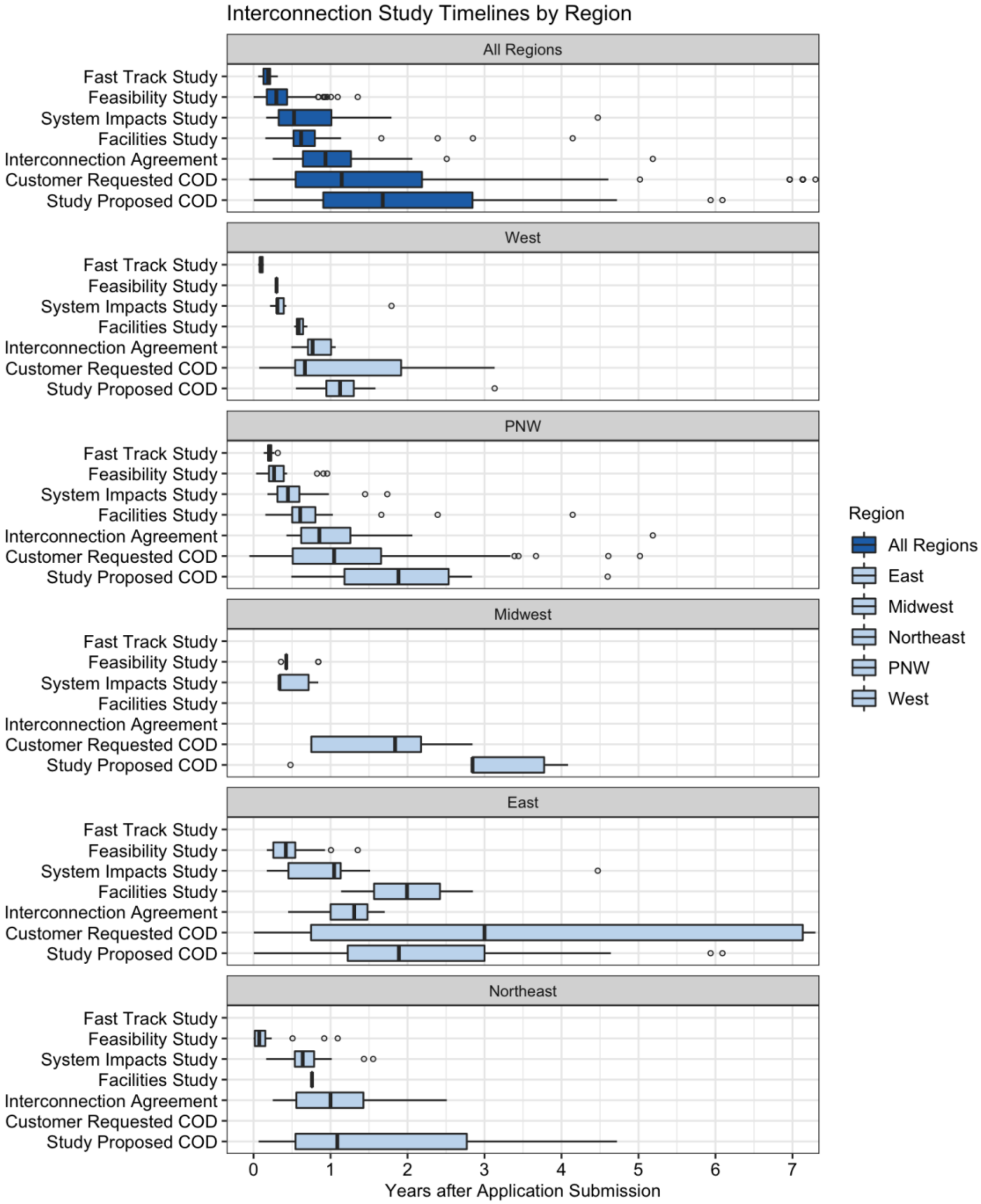



Figure B.1. Timeline between Application Submission and Interconnection Milestones Separated by Region of Interconnection

The interconnection process timeline differs for each queue owner and is influenced by the type of interconnection project. Interconnection applications for new generators take more time and have a wider range than applications for upgrading existing facilities for all milestones except the feasibility study (Figure B.2).

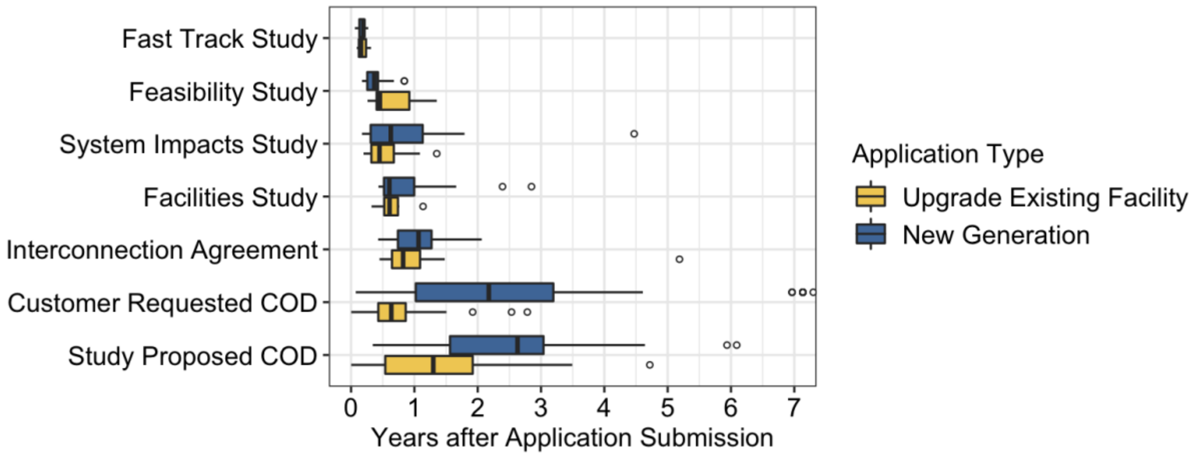



Figure B.2. Timeline between Application Submission and Interconnection Milestones, Separated for New Facilities and Upgrades

Although interconnection cost is likely a stronger driver of a project's success, longer interconnection study processes may also lead to a project being withdrawn from the queue. Projects that ultimately end up in service tend to have a shorter study process and earlier commercial operation date (COD) (Figure B.3). In most cases, the median, 25$^{th}$ percentile, and 75$^{th}$ percentile of applications are only a month or two different during the study process, whether the project is withdrawn or in service. The bigger difference is in the COD.

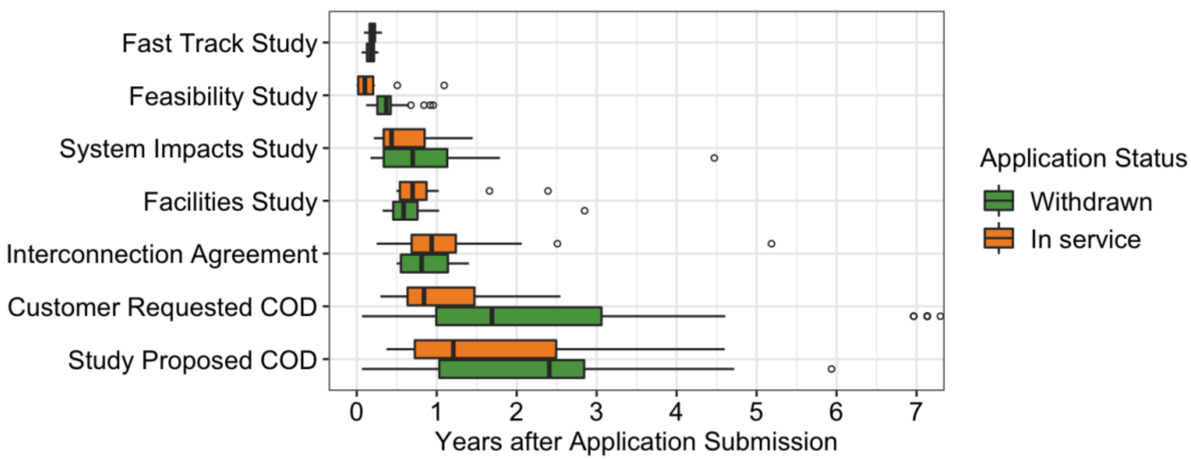



Figure B.3. Timeline between Application Submission and Interconnection Milestones, Separated into In-Service and Withdrawn Projects

Following Figure 6 in the main text, various characteristics of the project were explored but did not show an influence on the project schedule. For example, the POI voltage did not have a significant effect on the proposed COD. As expected, the proposed COD is longer for more expensive projects, but the relationship is not very strong because some expensive interconnections may not necessarily have a long timeline and others incur little or zero cost yet require significant processing time.

# Appendix C – Detailed Description of Upgrade Categories

What follows are precise descriptions of the individual upgrades and other pertinent information.

## C.1.1 Conductoring

Modern conductors are primarily made from stranded aluminum with their gauges (diameters) sized according to the quantity of electrical current they will transmit to grid-connected loads (customers). For instance, larger loads require more electrical current and thus larger conductors. For the purposes of this work, only three-phase, four-wire configurations are considered, meaning three primary conductors and a neutral. Conductoring upgrades were usually identified by utilities as a result of Facilities Studies and/or System Impact Studies.

### C.1.1.1 Pertinent Upgrades

- **New conductors** and ancillary equipment, such as power poles/structures and framing equipment, were required to interconnect the interconnection customer's generator to the utility's system when they did not already exist.
- **Conductor upgrades** were required when existing conductors became overloaded with the added capacity of the IC generator or in the absence of three-phase power.

## C.1.2 Substation

Where conductors are passive and mainly concerned with transmitting electrical current, substations take an active role in conditioning the system voltage, stepping the voltage up or down, protecting the downstream grid, and provide a means to interconnect (and disconnect) end-use customers to the grid. Substations come in different varieties such as those on the transmission system or on the distribution system. More details are provided below into how the functions of the substation relate to the upgrades identified by the utilities in the IC reports. Generally, the upgrades either augmented/modified existing substations or required new substations altogether. More complex upgrades such as adding or replacing major equipment generally fell into the "Expand Existing Substation" category, while less complex upgrades such as changing controls settings carry their own category. Reference Table 6 for a listing of upgrades.

### C.1.2.1 Expand Existing Substation

*Substation Function - Conditioning System Voltage*

In the United States, voltage levels should be maintained to within (+/-) 5 percent of the nominal value. The substation accomplishes this by employing voltage regulators and/or capacitor banks; since distributed generation can alter the voltage profile of the overall transmission and distribution grids, both can be required depending on factors such as the capacity of the IC generator. Substation regulators and capacitors are relatively complicated and costly upgrades and would be considered an "Expand Existing Substation" project. Potential upgrades include:

- Add voltage regulators.
- Update existing voltage regulators.
- Add capacitor banks.

- Update existing capacitor banks.

*Substation Function - Step Voltage Up or Down*

Power transformers perform a stepwise change in the nominal voltage value. Transmission system power transformers usually reduce the nominal voltage from transmission voltage (>69 kV) to sub-transmission voltage (39 kV–69 kV), while distribution power transformers reduce the voltage from sub-transmission voltage to distribution voltage levels (4 kV–35 kV). Conversely, reverse power flow through a power transformer would result in an up-step in the voltage; reverse power flow could occur if the IC generator was of sufficient size to cause a reversal (something to be avoided in most cases). Power transformers are necessary because system losses and material costs may be minimized by cascading the voltage level from source to loads. Power transformers are the crux and costliest single component of a substation and thus would fall into the “Expand Existing Substation” upgrade project. Potential upgrades include:

- Add power transformer.
- Upgrade existing power transformer.

*Substation Function - Protect the Downstream Grid*

The overall reliability of the grid is relatively good; however, naturally occurring or manmade events can result in transient anomalies or persistent power outages. The most common system anomalies are grid faults, voltage swings, and frequency swings. Faults can be transient in nature or persistent, but in either case, they usually result in a sudden surge of electrical current to levels sufficient to cause significant damage if gone unmitigated. Voltage spikes can be caused by surges in power from a distributed source or by natural causes, such as lighting strikes. Voltage slumps are typically caused by large loads switching on, or by the sudden loss of a power source, such as a distributed generator. Frequency swings are instigated by the same conditions that cause voltage disturbances. No matter the nature of the disturbance, the mitigating strategy is usually through constant monitoring and an abrupt break in the circuit should spurious conditions persist beyond limits.

Substations provide downstream system protection through a combination of circuit breakers, controlling relays, and ancillary devices. Circuit breakers are positioned immediately downstream of power transformers and at the head of distribution feeders, thus their influence affects the entire feeder along with all connected loads. While circuit breakers are the mechanism by which circuit interruptions may be incited, relays provide the monitoring and control over the circuit breaker’s function. Although relays and circuit breakers are manufactured with similar designs over various model classes by multiple equipment providers, their operational parameters are uniquely fashioned to match the unique characteristics of the feeder in which they protect. The protection is accomplished through a unique set of relay settings, which are developed through system modeling techniques. The settings provide the range in which the relay will incite an operation by the circuit breaker.

Because the relays and their settings are designed to be exclusive to the unique design and connected load profiles, if impactful changes are made to the feeder, it could mean that relays would need new settings or need to be replaced altogether. The same holds true for the substation breaker. Therefore, when adding a distributed generator, its impact to the protection and control scheme may justify upgrades or additions. Required protection and control upgrades can be complicated or relatively simple depending on the situation. Potential upgrades include:

- Add substation breaker and ancillary systems (new breaker, structural steel, switches, controls, relays, relay settings).
- Upgrade existing breaker and ancillary systems if necessary (new breaker, upgrade relay assemblies, update relay settings).
- Upgrade relay assemblies and relay settings.
- Update relay settings.

#### C.1.2.2 New Substation

Some interconnections called for new substations, the majority of which involved tapping an existing transmission or sub-transmission line. These were among the costliest upgrades and were common as well. The reader should note that in these cases the substation was an interconnection substation and served only to provide the necessary isolation switching at the point of the transmission tap. Therefore, voltage steps were not applicable and thus power transformers were unnecessary. Potential upgrades include a new substation.

#### C.1.2.3 New Relays

One of the less costly substation upgrades is replacing relays and updating their settings. This upgrade is often necessary when the substation is older with vintage relays that do not have the capability of sensing reverse power flow or when more advanced protection and control is needed.

#### C.1.2.4 Update Relay Settings

Of all the substation upgrades, this is the simplest, because no new hardware is required. Usually, the process involves performing system modeling studies, developing new relay settings, and programming those settings into existing relay assemblies.

### C.1.3 Line Protection and Control

This category refers to the same types and functions of voltage, frequency, and fault protection devices as were covered in the substation section above; however, they are located external to the substation along the feeder circuit. For this reason, their fundamental operating principles will not be covered again in this section.

Primarily, line protection and control upgrades are relevant only to interconnections on the distribution system; that is, POI voltage less than 35 kV.

#### C.1.3.1 Potential Upgrade: New voltage regulator

Line voltage regulators perform the same function as substation regulators in that they monitor the voltage level and correct it if necessary. Interconnections sometimes result in overvoltage disturbances or more frequent voltage swings than before, thus requiring new regulators.

#### C.1.3.2 Potential Upgrade: New Recloser

A recloser performs similar functions as the substation breaker; however, it cannot replace a breaker. Reclosers are placed along the feeder at some intermediate point between the substation and end of line. Just as breakers, reclosers monitor conductors for system faults, voltage swings, and frequency swings, and have the capability of acting independently in interrupting the circuit if necessary. Although independent, their control schemes allow them to coordinate with upstream breakers or other reclosers installed on the same feeder. On normal feeders, they are employed on long feeder circuits where the circuit breaker cannot adequately protect the entire circuit, or if the loads are erratically dispersed. They also provide an intermediate sectionalizing location that allows a portion of a feeder under fault conditions to be isolated, thus reducing the number of customer outages. Reclosers are controlled via relays just as circuit breakers.

For the purposes of distributed generator interconnections, they are employed to sense and react to reverse power flow brought on by the interconnected generator and to protect the circuit between it and the substation if reverse flow occurs. Reclosers are also controlled.

#### C.1.3.3 Potential Upgrade: New Line Relays

This upgrade refers to when a recloser is present, but the associated relay package has become insufficient because of the generator interconnection. This is especially the case when the existing relay package is incapable of sensing reverse power flow.

#### C.1.3.4 Potential Upgrade: Modify Existing Line Relays

The existing relay package is sufficient in this case; only the protection settings must be modified, requiring system modeling to develop a new complement of settings.

#### C.1.3.5 Potential Upgrade: New Fuses

Line fuses are normally only utilized on the distribution system because they are the most simplistic form of system protection and, once activated, they cannot reenergize a line automatically as circuit breakers and reclosers. They are also the last line of protection. This means that the preferable sequence of protecting against anomalies would be recloser action, circuit breaker, then fuses since customers are guaranteed to suffer a persistent outage as a result. Industry often refers to fuses as fused cutouts. They are sized according to the maximum expected electrical current under normal conditions and they are coordinated with upstream reclosers and/or circuit breakers so that they activate last as was just described.

New power generation on a circuit can alter the electrical current profile and thus require new fuses or newly sized fuses should they already exist.

#### C.1.3.6 Potential Upgrade: Visible Disconnect

Visible disconnects are simply switches that do not offer any type of system protection; they are present only to manually isolate a section of the circuit from the rest. Electric utilities utilize them when issuing clearances, when some types of maintenance tasks require a deenergized line. They are also referred to as open airgap switches because one can observe a gap between the switch terminals, thus signifying a deadline and that the line is clear and safe for maintenance. In this case, the utility would require a visible disconnect for safety purposes.

#### C.1.3.7 Potential Upgrade: Transfer recloser or voltage regulator

As previously mentioned, reclosers and regulators are only capable of protecting or controlling a finite section of the circuit, and they are strategically positioned on the circuit to optimize their performance according to system modeling. By interconnecting a distributed generator, the parameters of the entire circuit can be altered to the point where reclosers or regulators are no longer effective at their current locations, thus requiring a transfer. The new optimal locations are revealed by system modeling.

### C.1.4 Communications

Reliable system protection and control cannot be accomplished without a robust and reliable communications system. A very common communications/control system employed by nearly all electric utilities is the Supervisory Control and Data Acquisition (SCADA) system, which facilitates coordination between system protection devices such as reclosers and circuit breakers, but also allows system operators to monitor and control the system remotely. There are other communications systems, but they all utilize hardware and carrier mediums, such as microwave, radio, fiber optic, cellular, or telephonic, to transmit signals and data between affected system components and operations centers. Because interconnected generators will actively interact and affect the grid and its customers, they must employ a certain degree of the same functionality.

#### C.1.4.1 Potential Upgrade: Fiber Optic Cable Connection

Fiber optic cable is one of the fastest and most reliable methods to transmit signals and data between points. As was discussed in previous sections, system protection is paramount, and protection devices must execute protective actions on a millisecond timescale to avoid permanent system damage in some cases. Distribution or transmission feeders that do not have distributed generators interconnected on them have only one source of energy, the substation, and the substation breaker protects the entire feeder from damage. When multiple sources are present, they must all coordinate and essentially act in concert to protect the system when anomalies occur; this is infinitely more complicated than the single source case, especially when dealing in millisecond timescales. Thus, signals must be interchanged between protection devices very fast. Therefore, some interconnection projects required a dedicated fiber optic connection between the utility's protection devices and the interconnection customer's circuit interrupting device to enable direct transfer trip (DTT). In this way, when one device senses an anomaly, they are all essentially notified instantaneously to take the same action. Other, less impactful interconnections did not require fiber optic connections and DTT functionality.

#### C.1.4.2 Potential Upgrade: Install DTT Capability at Neighboring Substations/Control Centers

For some larger interconnections, particularly those involving the transmission system, DTT had to be enabled at multiple substations' breakers and system control centers. This was more costly because the effect of the interconnected generator was more widespread, so fiber optic connections had to be established between multiple points, which in some cases involved running very lengthy fiber optic lines.

#### C.1.4.3 Potential Upgrade: Telephonic Connection

This upgrade was usually required to facilitate the transmission of metering data or other telemetry data, such as distributed generator status to the electric utility. Cellular connections fell within this upgrade as well.

#### C.1.4.4 Potential Upgrade: Enable SCADA

As mentioned above, SCADA is a very common communications and control platform among utilities. Depending on the capacity of the interconnection, the utility usually required that the generator be accessible over the existing SCADA system for monitoring and control. Some SCADA facilitations were more complicated than others, with customers installing remote terminal units (RTUs) and/or hardlines to the utility's nearest RTU. In some cases, the interconnection prompted upgrades to the utilities' existing SCADA system, especially where new system protection devices were required.

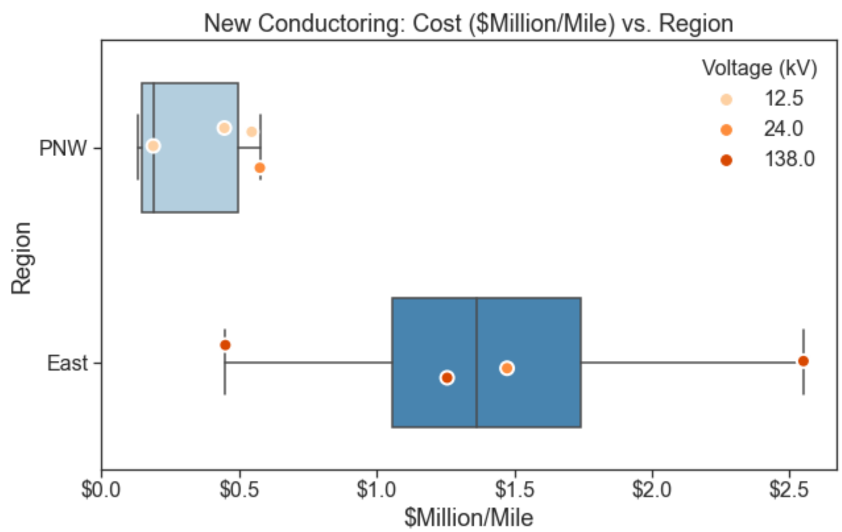
#### C.1.4.5 Potential Upgrade: Metering

Some form of metering functionality was required in almost all cases. The metering facilities usually included a dedicated power pole or erected structure, a normal complement of potential transformers and current transformers, meter enclosure, a commercial grade meter, and an established communications link over which status and output were transmitted to the utility.

# Appendix D – Reconductoring Cost Drivers

New and upgraded conductor costs along with length (miles) and POI voltage (kV) were tracked across the data where available. Figure D.1 shows the $/mile cost analysis as a boxplot across regions to better show the distribution of the available data. Additionally, the dots are shaded by POI voltage.

From Figure D.1, the generally higher costs of new conductors compared to upgraded conductors, on both a total cost and per mile basis, may be observed. Most reconductoring costs are under $1 million/mile and $1 million outright. Additionally, this figure shows that the Northeast appears to have higher conductoring costs than the Pacific Northwest; however, there is limited data available, limiting any strong conclusions.



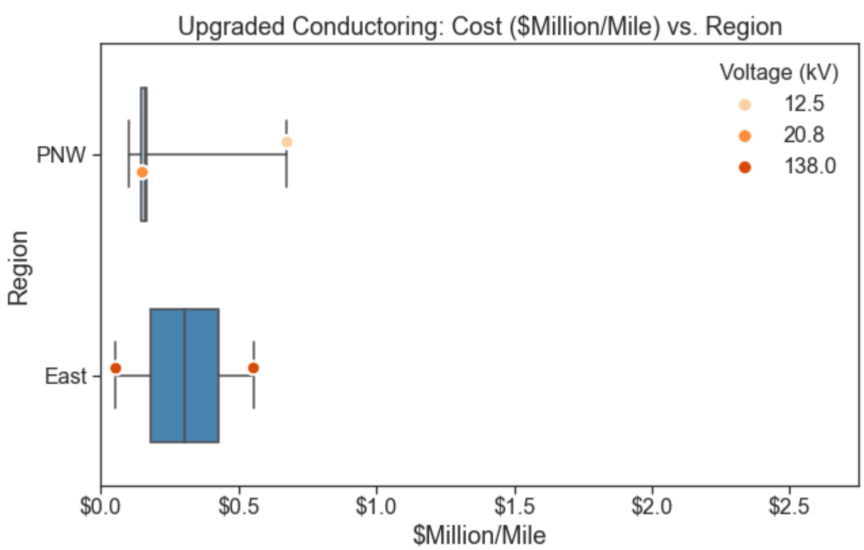




Figure D.1. New Conductoring and Upgraded Conductoring Cost ($million/mile) by Region

Figure D.1 also shows a clear pattern between higher POI voltage and the associated cost on a per mile basis. Nearly all of the POI voltages in the Eastern region are higher than those in the Pacific Northwest, and the median cost difference between the two regions is substantial for new conductors. For upgraded conductors, the cost between the two regions is more comparable, with no clear association between voltage and cost. Limited data was available, however, so highly conclusive takeaways are limited at this time.

Figure D.2 shows the combined total reconductoring cost (both new and upgraded) in both $million and $million/mile. Similar to the plots above, the data is colored based on region. The lower plot shows the distribution of the $million/mile data by region. This plot shows the significant cost difference for reconductoring between the Pacific Northwest and the Eastern region. Note that there are only four datapoints shown for the Eastern region in the lower plot due to both new and upgraded conductors occurring in the same project on two occasions; this drops the number of total datapoints accordingly when the two types are summed.

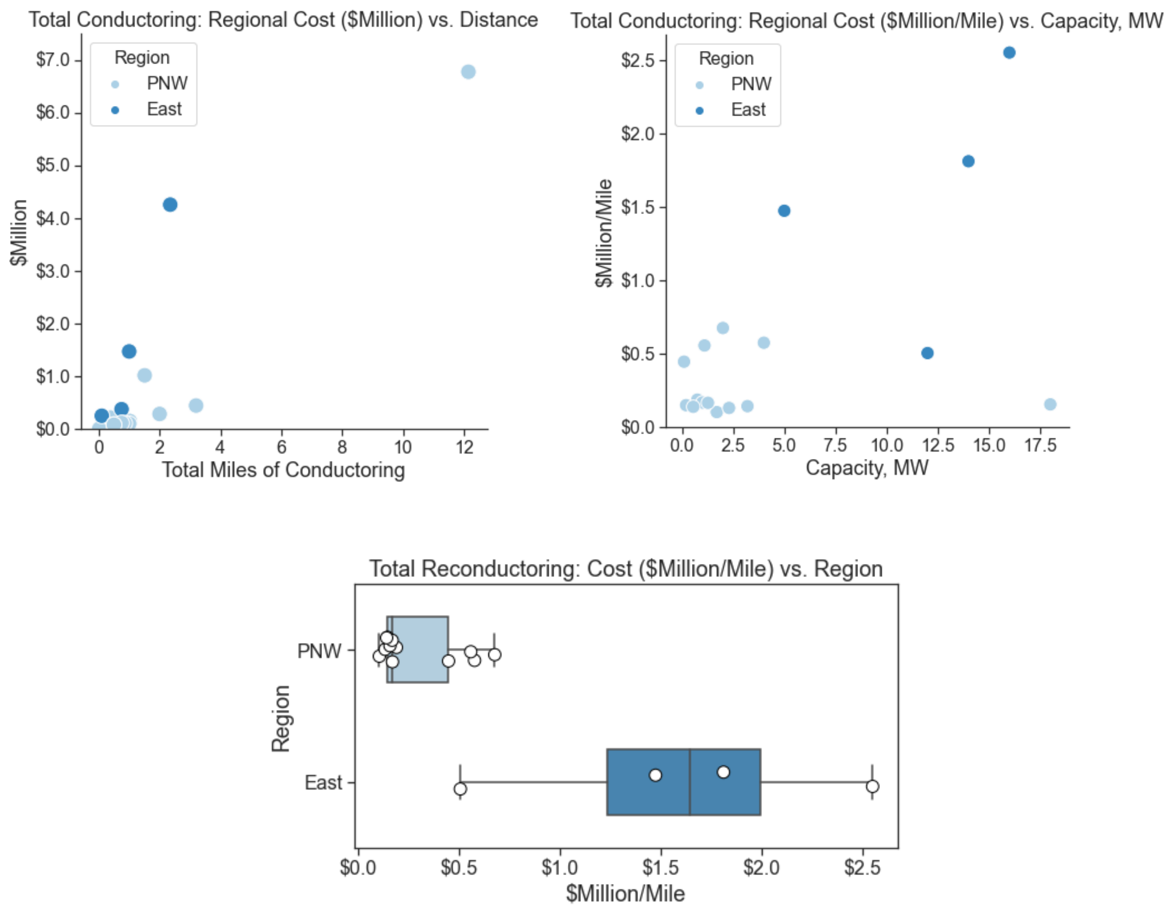



Figure D.2. Total Reconductoring Cost in both $million vs. Distance (Left), $/mile vs. Capacity (Right), and $/mile by Region (Bottom)

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