Least-cost Optimal Distribution Grid Expansion (LODGE)

Utility Pilots

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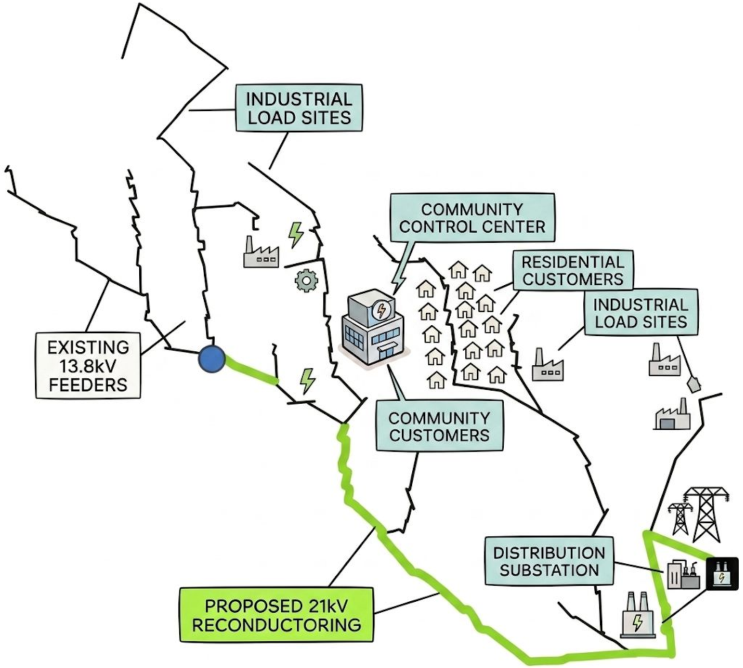
LODGE: Least-Cost Optimal Distribution Expansion

- The Least-cost Optimal Distribution Grid Expansion (LODGE) model provides **the optimal portfolio of distribution system upgrades** to interconnect distributed energy resources (DERs) and to support load growth.

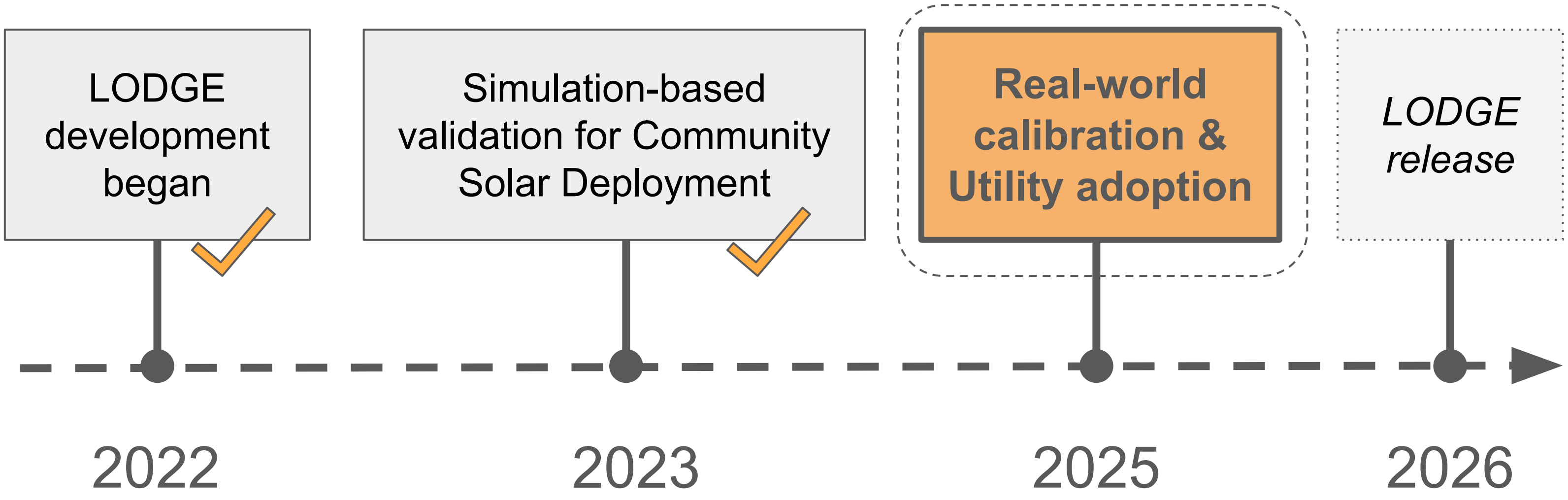
- Available investments include **voltage regulators, feeder reconductoring, transformer upgrades and non-wires alternatives (NWA)**, such as strategic siting of **storage and distributed generation**.

- LODGE can be used to assess grid infrastructure costs and explore policy and regulatory solutions for **distribution planning** and **DER valuation**.



Why These Pilots Are Important

These pilots allowed the validation of LODGE results with real utility data before its first release in 2026



Pilot #1: Seattle City Light (SCL)

Objective:

Identify 10 feeders to install up to 4 MW of community solar (CS) projects

Approach:

- Generate up to 4 MW deployment of CS projects across feeders in SCL territory
- Use the LBNL LODGE model to quantify grid upgrades and deferrals
- Assess the ability of CS projects to meet demand, particularly in the winter.

Pilot #1: SCL Main Results

Top 10 Feeders Identified

We identified the top 10 feeders where PV community solar would lead to the lowest grid investments across a range of deployment capacities (500–4,000 kW per feeder)

Load Growth Cuts Upgrade Costs

Higher load absorbs more PV locally, **lowering added cost per kW** by:

- **13%** for the 2030 load
- **31%** for the 2040 load

Winter Load Supply

With 4000-kW of CS capacity per feeder, PV would supply a median of:

- **47%** of 2030 added winter load
- **16%** of 2040 added winter load

Pilot #1: Key Findings and Impact

- Most feeders **can integrate significant** distributed PV without requiring investments in line reconductoring or voltage regulation
- **Transformer capacity is a key determinant of PV adoption costs**, which significantly increase for higher target adoptions
- Battery storage deployment and operation can enhance PV hosting capacity by shaving peak demand while potentially avoiding additional reconductoring investments

Impact and next steps:

- SCL plans to use the maps to inform community solar project siting
- The LODGE team has been invited to participate in a utility-wide information session to present the results to the SCL staff
- LODGE is being used in new SCL-LBNL project to inform the utility Integrated Resource Planning

Pilot #2: Public Service Company of New Mexico (PNM)

Objective:

Identify locations for CS projects and strategies to facilitate its integration

Approach:

- Generate deployment scenarios to build community solar projects throughout selected feeders
- Explore alternatives to maximize CS adoption (particularly, battery storage and distribution across feeder)
- Analyze impacts on distribution system planning and the value of PV deployment

Pilot #2: PNM Main Results

Ideal location for PV deployment

We identified the effect of PV deployment location on PNM feeders, where concentrated PV towards the end of the feeder generally leads to higher investment costs

Best feeders for PV deployment

The top 10 feeders for CS deployment considering different assumptions of CS capacity (2–8 MW), siting, and utility-scale battery deployment

Identified benefits from battery storage

Utility-scale battery storage provides an alternative to reshape load profiles and avoid expensive reconductoring investments

Pilot #2: Key Findings and Impact

- Median costs of integrating CS **remain below $6.78/kW** of installed solar for capacities above 3000 kW if installed at intermediate location on the feeder rather than the end-of-line siting, near where load is concentrated
- The range of added costs spikes from around **$5/kW-year to $45/kW-year** as PV deployment per feeder increases **from 3000 kW to 5000 kW**.
- CS deployment is significantly **more valuable under high-demand conditions**, with median values of $6.7–6.8/kW-year, compared to $1.0–1.8/kW-year under base-load conditions.

Impact (quoted from PNM representative during the pilot result presentation to NM PRC):

- “*The feeders that were ranked higher in the overall results were the feeders that were heavily loaded and that means that they would have greater hosting capacity. So being able to use this tool to site additional solar in multiple locations could be useful*”

Pilot #3: La Plata Electric Association (LPEA)

Objective:

Understand how high PV adoption affects required distribution grid investments in LPEA territory, including investments to enable PV adoption and mitigate reverse power flow conditions

Approach:

- Identify the maximum distributed PV capacity that can be installed **without additional investments**.
- Evaluate impacts of **reverse power flow limits** and battery storage deployment, where possible.

Pilot #3: LPEA Main Results

Substation Capacity: Half of LPEA substations should be able to add greater than 4 MW of distributed PV.

Deployment Scaling: Around half of the worst cases have deployments over or near 200% of their minimum daytime load.

Investment Reduction: Additional PV can reduce under-voltage conditions, appearing to reduce investments despite PV increase.

Grid Flexibility: Expensive battery investments can be avoided by relaxing substation reverse power flow limits.

Pilot #3: Key Findings and Impact

- Of the 22 substations evaluated, **nearly half** (10) will likely see **no distribution planning impacts** from additional distributed solar up to 200% of MDL.*
- For most feeders, LODGE identifies potential **over-voltage** conditions that **drive investments** in voltage regulators.
- **Limiting** substation **reverse power flow** can be **expensively** accomplished by batteries, relaxing this constraint results in significant savings

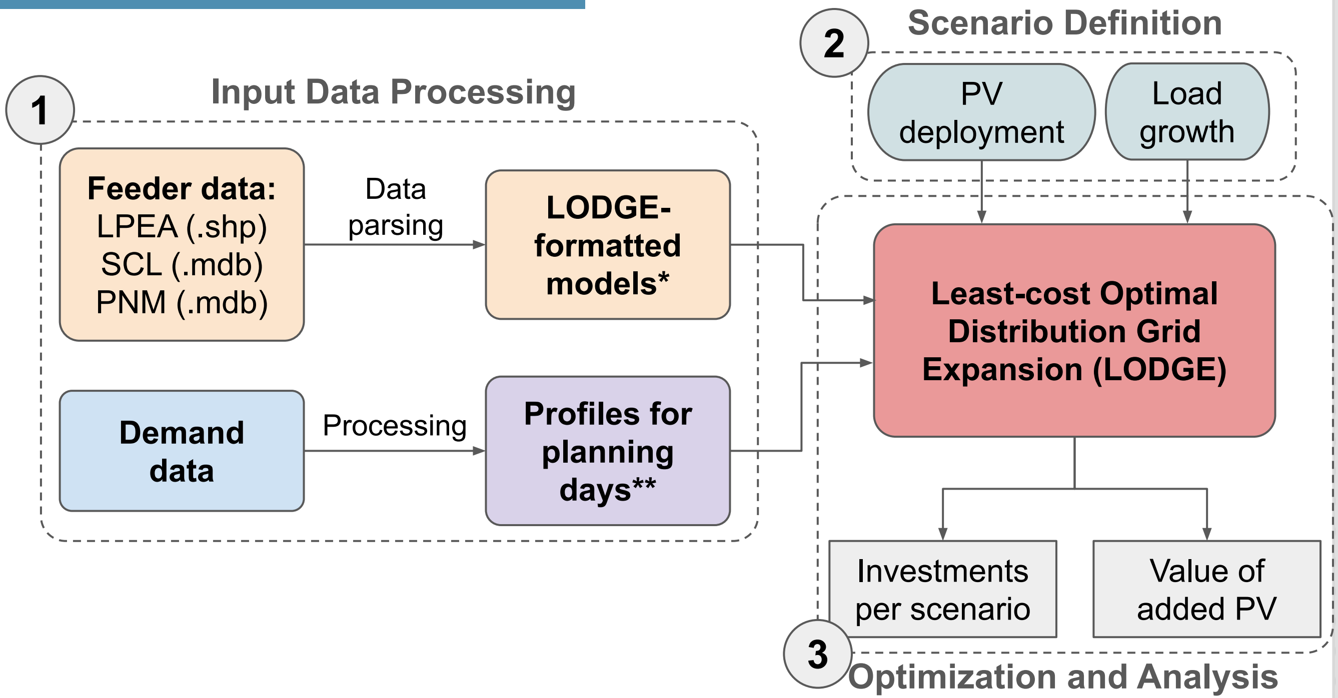
Impact

- LPEA wants to use this analysis to inform investments needed to accommodate the deployment of distributed solar. Planned to present our work to their board to inform decisions on infrastructure upgrades.

Implementation

For each pilot, the workflow considered:

1) **Feeder reconstruction and input data wrangling** into a LODGE-compatible format
2) Definition of PV deployment and load growth scenarios based on utility requirements
3) Investment optimization with LODGE and cost analysis from adoption



*feeder models for SCL and PNM, substation models for LPEA
**maximum net load, minimum daytime load, average load

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LODGE Pilots in Numbers

Across the three pilots:

292 feeders

562,518 consumers

3,838 LODGE runs

- Five attributes of the latest LODGE model
  - ✓ Enhanced identification of grid needs and opportunities to defer or avoid upgrades across multiple DER investment strategies
  - ✓ Improved overall model stability and speed
  - ✓ Enhanced topology analysis for non-three-phase sections
  - ✓ Improvements on voltage regulators and capacitors placement
  - ✓ Custom modeling for capacitors as switchable devices

Results for SCL

Considerations

Approach:

- Run simulations across 154 feeders of up to 4 MW of CS projects (considering 0.5, 1, 2, and 4 MW)
- Considers distributed additions in given capacities
- Assess the ability of CS projects to meet demand, particularly in the winter.

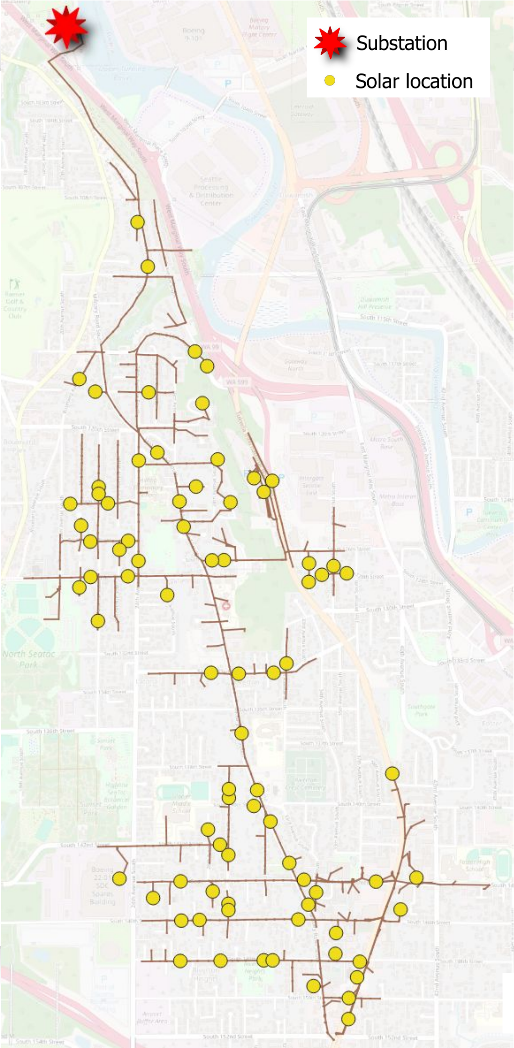
Data:

- LODGE applied to 154 feeders across SCL territory
- AMI data at transformer level for year 2022
- 15 LODGE runs per feeder, comprising a combination of 5 distributed PV and 3 load scenarios.
  - **A:** Base case, no PV
  - **B**: 500-kW PV deployment
  - **C**: 1000-kW PV deployment
  - **D**: 2000-kW PV deployment
  - **E**: 4000-kW PV deployment
  - Load Scenarios: 2022 (base load), 2030, 2040 (load growth)

SCL Pilot Methodology

Community Solar Deployment

- Deployment of CS is **randomly assigned** among the service transformers in each feeder
- Each solar unit is rated among the following capacities: 50 kW, 70 kW, 182 kW, 199 kW, 390 kW, and 750 kW
- PV is installed on the high-voltage side of the transformers
- CS installation on the secondary side does not impact primary voltages



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Load Growth Assumptions

- Load growth is based on SCL demand forecasts projected for the IRP. A homothetic growth is considered across substations.

- Added building and transportation electrification based on normalized profiles:
  - Building electrification (BE) and additional cooling (AC) from ResStock data
  - Transportation electrification (TE) profiles from NREL's OCHRE

- To allocate the load growth of each adoption category (BE, TE, AC):
  - Select a transformer
  - Scale the normalized profile considering the transformer capacity
  - Repeat until reaching the expected growth for the load type

Investment Analysis

- Base assessment based on power flow evaluation on peak cases
  - Winter peak (maximum load)
  - Summer peak (minimum daytime load)
  - Year peak (if occurring out of winter period)
- Least-cost line investments are defined based on maximum loading during peak
  - Lines with **loading greater than 50%** are identified for upgrading
  - Analyzed over all hours of the selected planning days (including winter/summer peak)
- Transformer upgrades are defined based on PV installations
  - Transformers are considered for upgrading if their loading **exceeds 140% for overhead transformers** and **100% for underground transformers**
  - Transformer investments depend on PV siting and need to be evaluated over a yearly profile
    - First, the set of transformers that need upgrade with no PV is identified
    - Second, the expected transformer upgrade cost/deferral when PV is added is obtained

Estimating Expected Transformer Upgrade Costs

- We estimate how different combinations of PV capacities (represented by added units $x_1,...,x_6$) contribute to the expected investment costs in transformer upgrades

- This helps determine which feeders are more prone to experience larger transformer investments to meet certain PV adoption levels

$$T = \sum_{t \in X} \sum_{i \in C} \frac{x_i}{N_{transformer}} C_{t,i}$$

$C_{t,i}$: added/deferred cost from installing PV capacity *i* at transformer *t*
X: set of transformers in the feeder
C: set of considered PV capacities
x_i: number of PV units of capacity i to be installed

Candidate PV capacities
↓
PV unit combination to meet CS capacity to install
↓
Expected cost estimation per combination
↓
Average expected cost across combinations

Feeder Ranking

Feeders are ranked based on the additional costs from deploying a PV target capacity (PVcap). For each feeder, the score is calculated as:

$$Score_{PVcap} = \frac{L + T + VR}{PV_{cap}} \quad [\$/kW]$$

***L**: added annualized investment on line reconductoring*
***T**: added expected annualized investments on transformer upgrades*
***VR**: added voltage regulation investments per year*

Ability of CS to Meet Feeder Demand

- Indicator M_1 is obtained to quantify the ratio of PV generated energy that is consumed by the feeder load, defined as:

$$M_1 = 1 - \frac{PV_{re}}{PV_{gen}}$$

  - PV_{re} is the total reverse energy measured at the substation
  - PV_{gen} is the total energy generated by the adopted PV

- M_1=1 means that all the PV generation is consumed by the load
- Any *excess energy* that is not consumed within the feeder will lead to a reduction in the metric

SCL Results:
Feeder Ranking

Top 10 - 4000 kW of PV Adoption

- Feeders enabling **line investment deferrals** (e.g., F011) are given top priority for deployment, as they lead to the lowest cost per kW deployed
- The remaining feeders in the ranking have no line deferrals and are prioritized based on the **least expected transformer investment**
- The presence of high-capacity transformers correlates with lower upgrade requirements and their related costs

Feeder	Maximum load (MW)*	Additional line investment ($/year)**	Additional transformer investment ($/year)	Score	Peak reduction (%)	Ratio of CS used to cover feeder load
F011	23.23	-13,439.05	16,939.31	0.88	2.04	1.00
F001	6.46	0.00	9,472.55	2.37	4.01	0.99
F003	10.08	0.00	10,080.41	2.52	0.00	1.00
F007	7.82	0.00	10,140.15	2.54	0.00	1.00
F013	11.41	0.00	10,761.56	2.69	4.97	1.00
F004	11.76	0.00	10,935.89	2.73	2.75	0.98
F002	4.15	0.00	11,176.45	2.79	18.24	0.82
F014	6.87	0.00	11,232.99	2.81	0.00	0.88
F005	5.23	0.00	11,716.50	2.93	0.00	0.96
F006	2.26	0.00	11,802.86	2.95	7.59	0.42

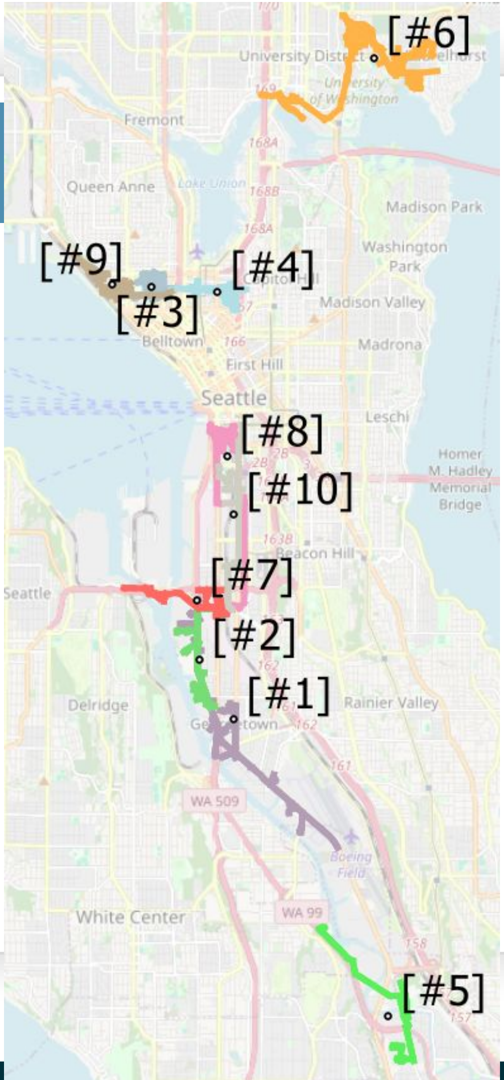
**Load before PV deployment*
***Negative values denote deferrals*

Best Ranked Feeder Location

Installations up to 4000 kW are preferred in feeders with large transformers, which have larger capacity and are less likely to require upgrades (locations shown in Fig.)

Feeders within the top 10 are mainly located in central areas with **high-density corridors** where existing infrastructure supports PV integration

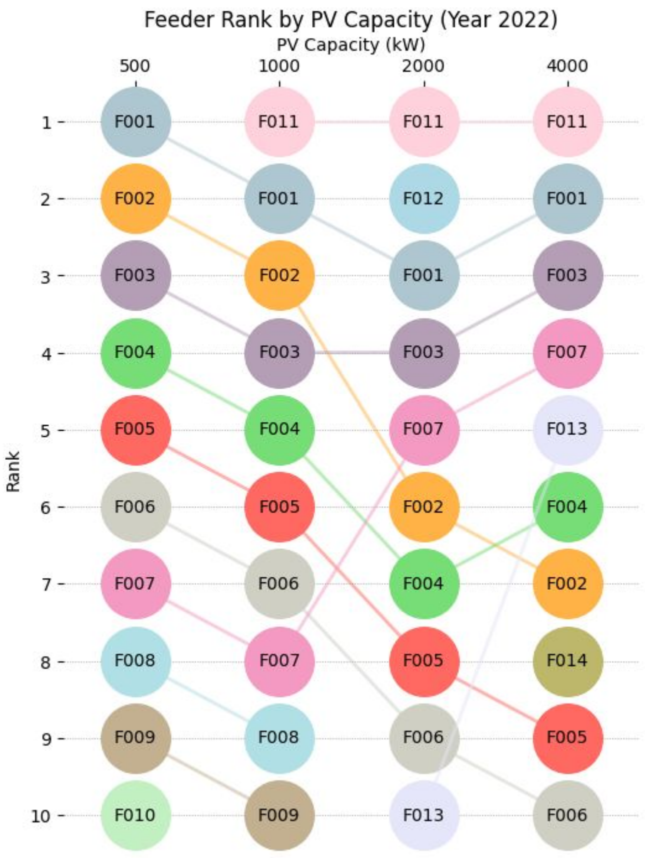
While high-capacity feeders are prioritized due to lower upgrade costs, the **actual physical capacity to install must be further explored by the utility**



Top 10 Across PV Adoption Levels

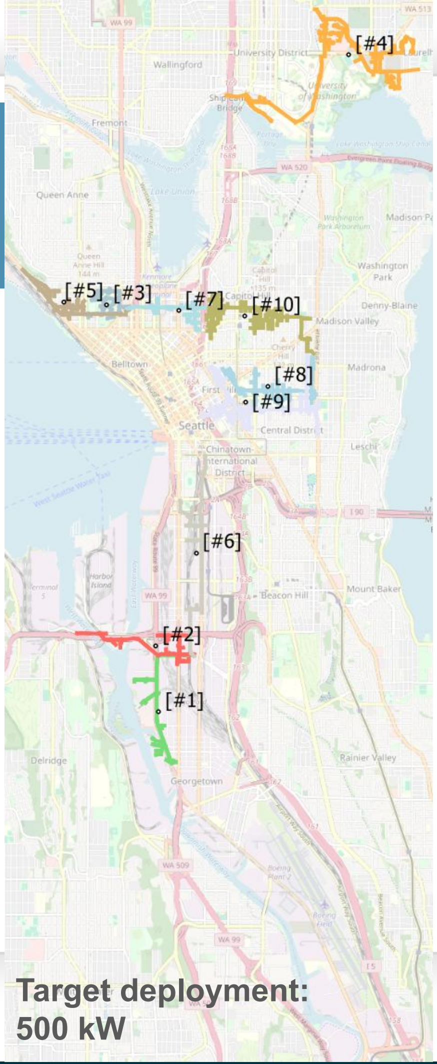
- A comparison of feeder prioritization based on the target PV deployment per feeder is shown in Fig.

- Feeder rankings shift dynamically based on targeted PV capacity, with some feeders being better ranked for lower PV deployment:
  - *Feeder F002:*
    - Contains a large, overloaded transformer; PV installation helps alleviate this overload (up to 1000 kW)
    - Requires multiple PV installations on individual transformers for PV above 2000 kW, increasing costs
  - *Feeder F011*
    - Deferrals on line investments for PV adoption of 1000 kW (or above)

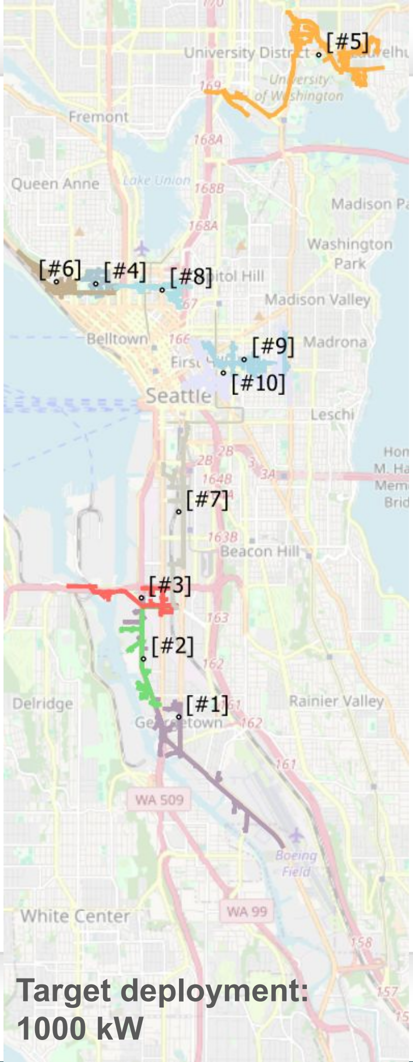


Location of Best Ranked Feeders

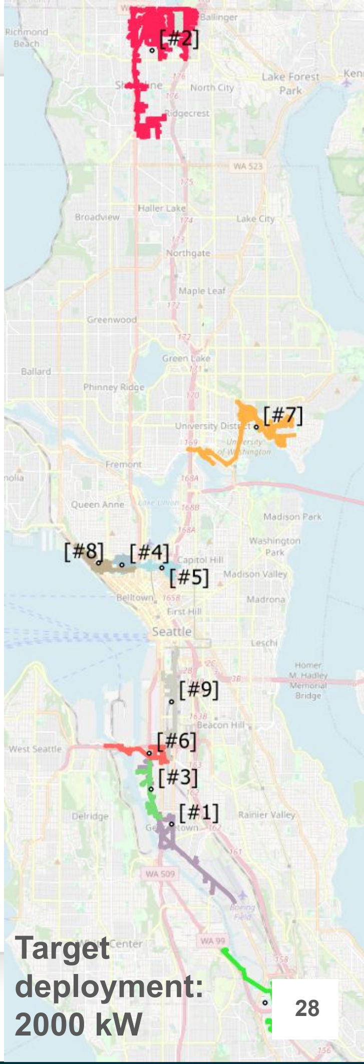
- The best locations for PV deployment are not static and shift based on the target capacity
- At maximum PV capacity, **deployment is prioritized to feeders with broader customer coverage**



Target deployment: 500 kW



Target deployment: 1000 kW



Target deployment: 2000 kW

SCL Results:
Effect of Combined Load Growth and PV Deployment

Effect of Load Growth

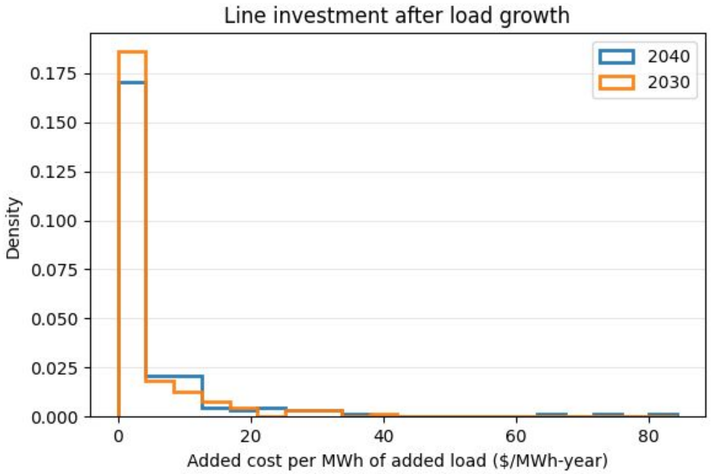
Load growth imposes additional line reconductoring: 30.7% and 51.6% of feeders need additional investments for 2030 and 2040, respectively

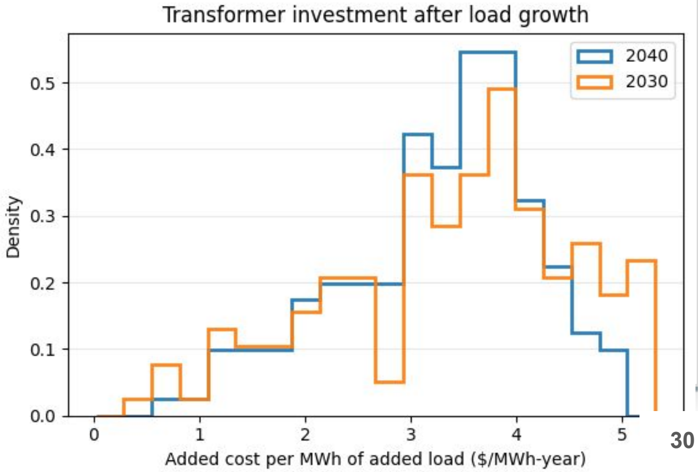
Line investment costs per MWh scale sharply between 2030 and 2040 (increasing by roughly 72%) → a larger percentage of the network exceeds thermal limits as load growth continues triggering widespread reconductoring

Transformer costs remain stable or decrease slightly by 2040 → Significant upgrades required for the 2030 load likely provide sufficient latent capacity to absorb the 2040 load without additional replacements

Average cost increase per MWh of added load

Year	Asset	Average added cost per MWh of additional load ($/MWh-year)
2030	Line	9.99
	Transformer	3.47
2040	Line	17.16
	Transformer	3.24

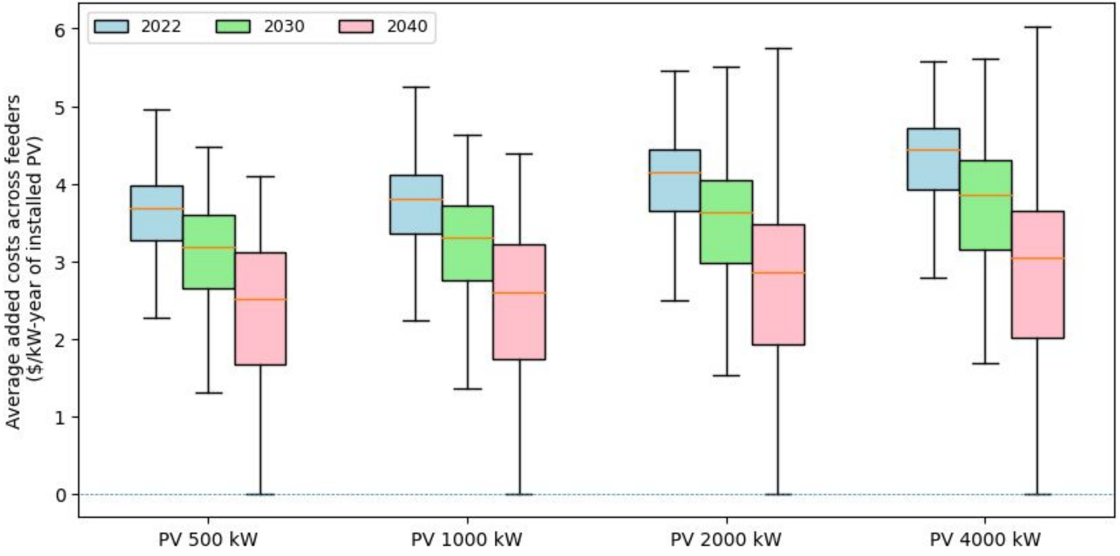




Combined Effect of PV and Load Growth

While median investment **costs increase with PV adoption,** the projected load absorbs solar generation, effectively **lowering the added cost per kW** by 13% for the 2030 load, and 31% for the 2040 load

As feeders are upgraded to handle the projected load, these upgrades also offer an opportunity to increase hosting capacity for future PV projects



Feeder Ranking Under 2030/2040 Load

Feeder rankings are sensitive to energy consumption, resulting in **different feeder selections** across scenarios

Feeders with more overloaded elements under high-load scenarios have the greatest potential for deferring investment when PV is deployed

Fig. Feeder ranking for multiple PV target deployment and anticipated 2030/2040 load growth

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SCL Results:
Ability of Deployed PV to Cover Winter Load

The Role of Storage in Addressing New Load

- Peak demand for feeders occurs between hours 18 and 20, which is **misaligned from the PV generation window**
- **Reconductoring cannot be deferred** by PV deployment as it is driven by the maximum feeder load
- Battery energy storage offers an alternative to **shift solar energy to the peak demand hours**, potentially avoiding investments on line reconductoring

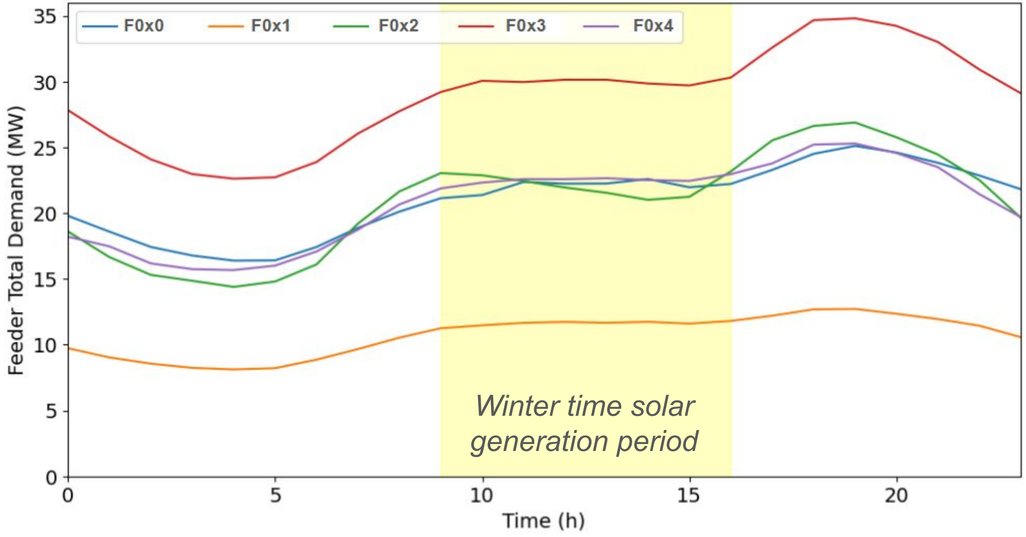


Fig. Load profiles for 2040 peak demand day for 5 feeders that require reconductoring

Potential to Meet New Winter Load

$$Ratio = \frac{SolarGen(PVcap, winter)}{Demand_{winter}^{target\_year} - Demand_{winter}^{base\_year}}$$

With a 4000-kW PV adoption, the median percentage of new winter load to be supplied with PV is **47% for 2030**, dropping to **16% for 2040** due to load growth

Feeders with smaller base loads can fully meet their increased demand with solar energy, provided batteries are used to distribute the energy throughout the day

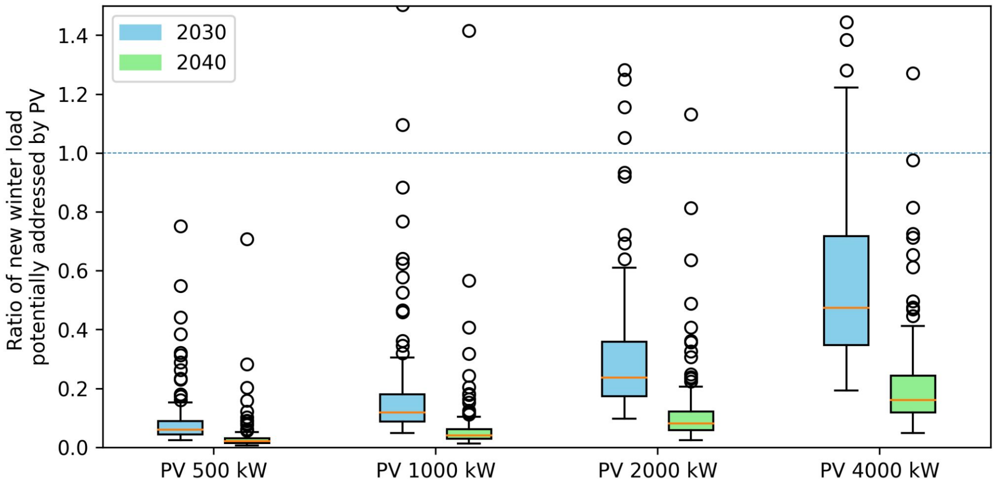


Fig. Distribution of the ratio of winter load per feeder covered by a 4000 kW PV deployment at each feeder. Values above 1 indicate generation exceeding load

Impact of PV on Winter Load Coverage

The relative contribution of 4000 kW PV installations to the winter load decreases as the demand increases from 2030 to 2040

Peripheral feeders show the lowest PV coverage levels, more noticeable for the 2040 load

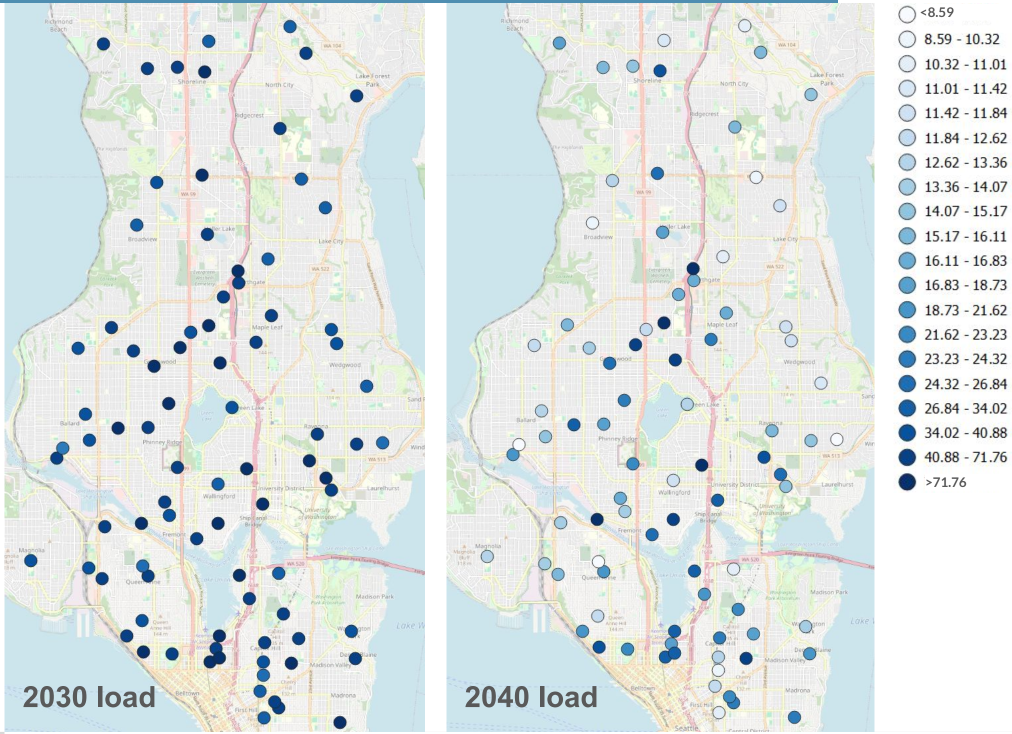


Fig. Percentage of winter load covered by 4000 kW of deployed PV capacity. The darker the color, the higher winter load covered by PV.

Key Findings

- Most feeders **can integrate significant** distributed PV without requiring investments in line reconductoring or voltage regulation
- Transformer capacity is a key determinant of PV adoption costs, which significantly increase for higher target adoptions
- Battery storage deployment and operation can enhance PV hosting capacity by shaving peak demand

Future use of these results:

- SCL will extend this information to groups working on community solar integration to decide on locations for community solar deployment

Impact for the Utility

- The results are part of the Community Solar Project to be developed by SCL
- SCL plans to use the maps to inform their community solar project
- New project featuring LODGE in progress
  - LODGE is used to inform the utility Integrated Resource Planning
- The LODGE team has been invited to participate in a utility-wide information session to socialize the results with SCL staff

Results for PNM

PNM Pilot Objectives

- Identify ideal locations to build community solar (CS) projects by ranking PNM feeders in terms of distribution upgrade costs needed to integrate CS

- Explore alternatives to accommodate CS in the distribution grid, namely:
  - distributing CS projects across different points of the feeder
  - pairing CS with battery storage

- Analyze impacts on distribution system planning:
  - Quantify additional grid costs or deferrals associated with the presence of CS
  - Capture the locational value of community solar

PNM Pilot Methodology

Setup and Analysis

- Setup
  - **Community Solar Target Capacity per Feeder:** 3000 kW, 5000 kW, 8000 kW
  - **Community Solar Location:**
    - Intermediate node in the longest three-phase branch (middle location)
    - Final node in the longest three-phase branch (end-of-line location)
  - **No Limitations on Reverse Power Flow at the Feeder Level**
  - **Load Scenarios:** Base year (2023-2024), 10-year future load assuming a 2% constant growth rate
  - **Planning days:** Maximum net load day, Minimum daytime load day, Average Day
  - **Utility-scale Battery Energy Storage**: Storage is enabled in large PV adoption cases to assess its impact on PV integration

- Different combinations of CS and load growth result in 18 scenarios evaluated in the LODGE model

Summary of Cases

Base case	Base load with existing PV, no additional PV	Case 1
Effect of capacity	Mid location prioritized, different capacities	Case 2: 2500 kW at middle location Case 4: 4000 kW at middle location Case 6: 5000 kW at middle location
Effect of CS location	End location prioritized	Case 3: 2500 kW at end location Case 5: 4000 kW at end location Case 7: 5000 kW at end location
Effect of load growth	Load is increased assuming a constant rate for 10 years	Cases 8-14: Cases 1-7 with increased load
Effect of battery addition	Enabled storage investment, 8-MW adoption case	Cases 15-18: cases 6-7 and cases 12-13 with battery investments enabled

Investment Analysis

- Base assessment based on power flow evaluation on peak cases
  - Maximum net load hour
  - Minimum daytime load hour
    - ➢ *Identification of feeders with voltage and overloads issues*

- Least-cost line investments and voltage regulation are defined based on maximum loading during peak
  - **Lines with loading greater than 95% are identified for upgrading**
  - **Voltage limits on the three-phase network between ±5% of rated voltage**
  - Analyzed over all hours of the selected planning days (maximum peak, minimum net load, average)

Feeder Scoring and Ranking

Feeders are ranked based on the additional costs from deploying a target PV capacity (*PVcap*), with a score calculated as a function of the additional feeder investments when compared with a no-deployment scenario:

$$Score_{PVcap} = \frac{L + C + VR}{PV_{cap}} \quad [\$/kW]$$

***L**: added annualized investment on line reconductoring*
***C**: added investments on capacitor installations per year*
***VR**: added voltage regulation investments per year*

PNM Results: Effect of PV Deployment Siting and Sizing

Effect of PV Deployment

Median added costs remain below $6.78/kW of installed solar when most of PV is installed at an intermediate location (for deployment over 3000 kW)

The number of feeders with added costs increases with PV deployment; most added costs occur **when PV grows from 2500 kW to 4000 kW**, and reduces the value per kW installed in the large adoption scenario

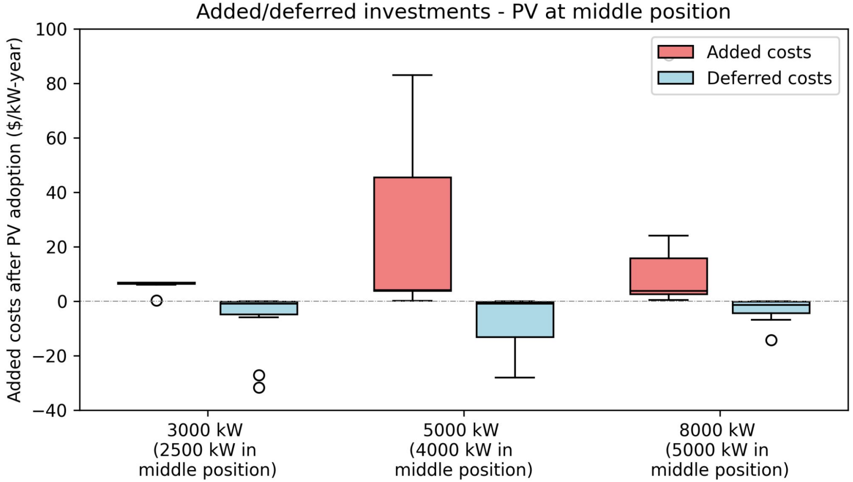


Fig. Distribution of added and deferred costs in different scenarios of CS deployment.

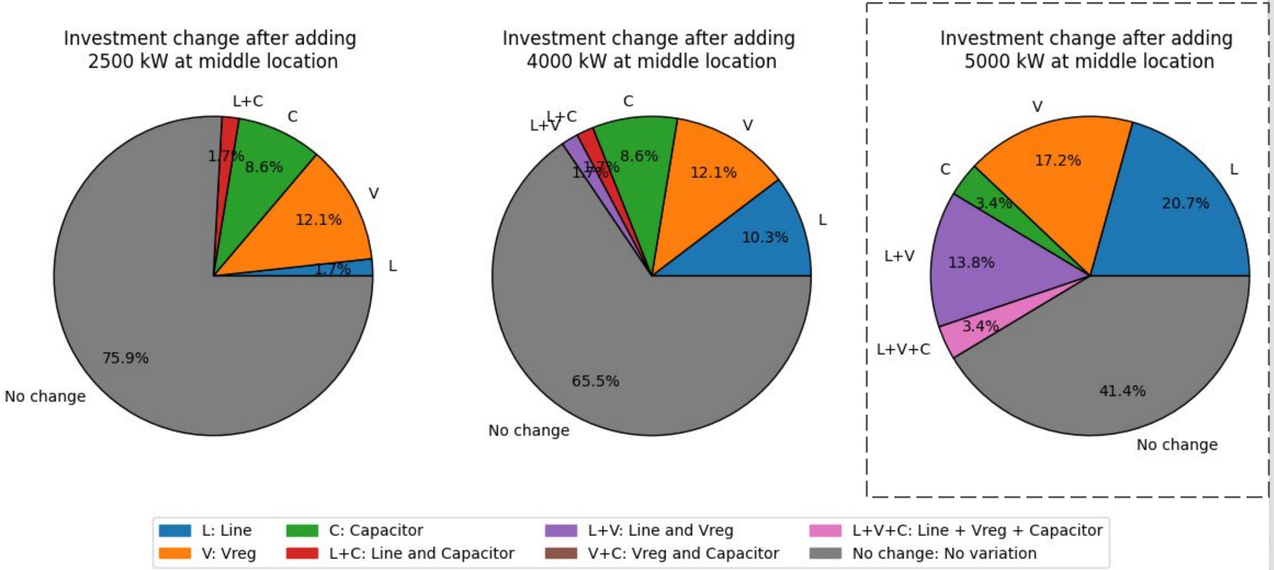
Table. Number of feeders with added/reduced/no investment changes compared to the base case

	PV deployment level		
Investment impact	**3000 kW PV**	**5000 kW PV**	**8000 kW PV**
Increased inv.	10	17	31
No change	31	27	17
Deferred inv.	17	14	10

Investment Change With CS Capacity

Up to 4000 kW, 65% of the feeders do not require upgrades, indicating a safe spot for medium-scale PV integration

Larger deployment significantly increases the number of feeder that require investments requiring multi-asset reinforcements

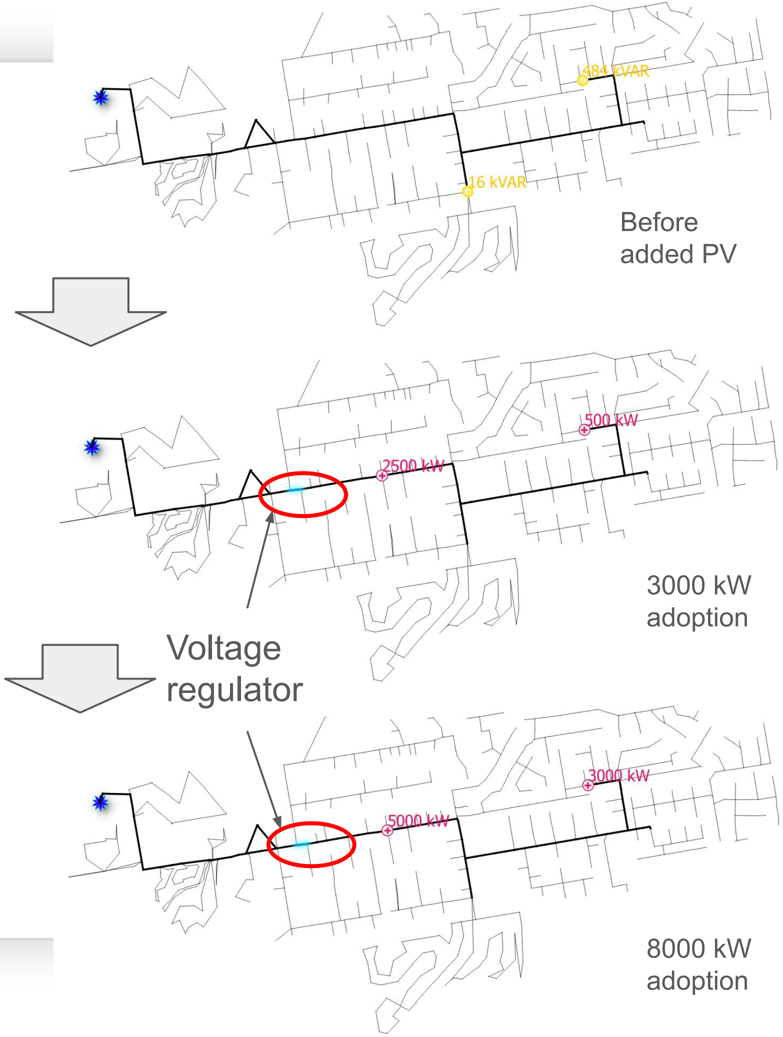


Feeder F013

A single voltage regulator addition is the only investment needed for the 3-MW deployment scenario.

Even when deployed capacity is increased up to an 8-MW deployment, no additional investments are triggered

For this feeder, **the cost per kW of installed solar reduces as the PV capacity increases**, showing higher-capacity scenarios are the most cost-effective for the utility

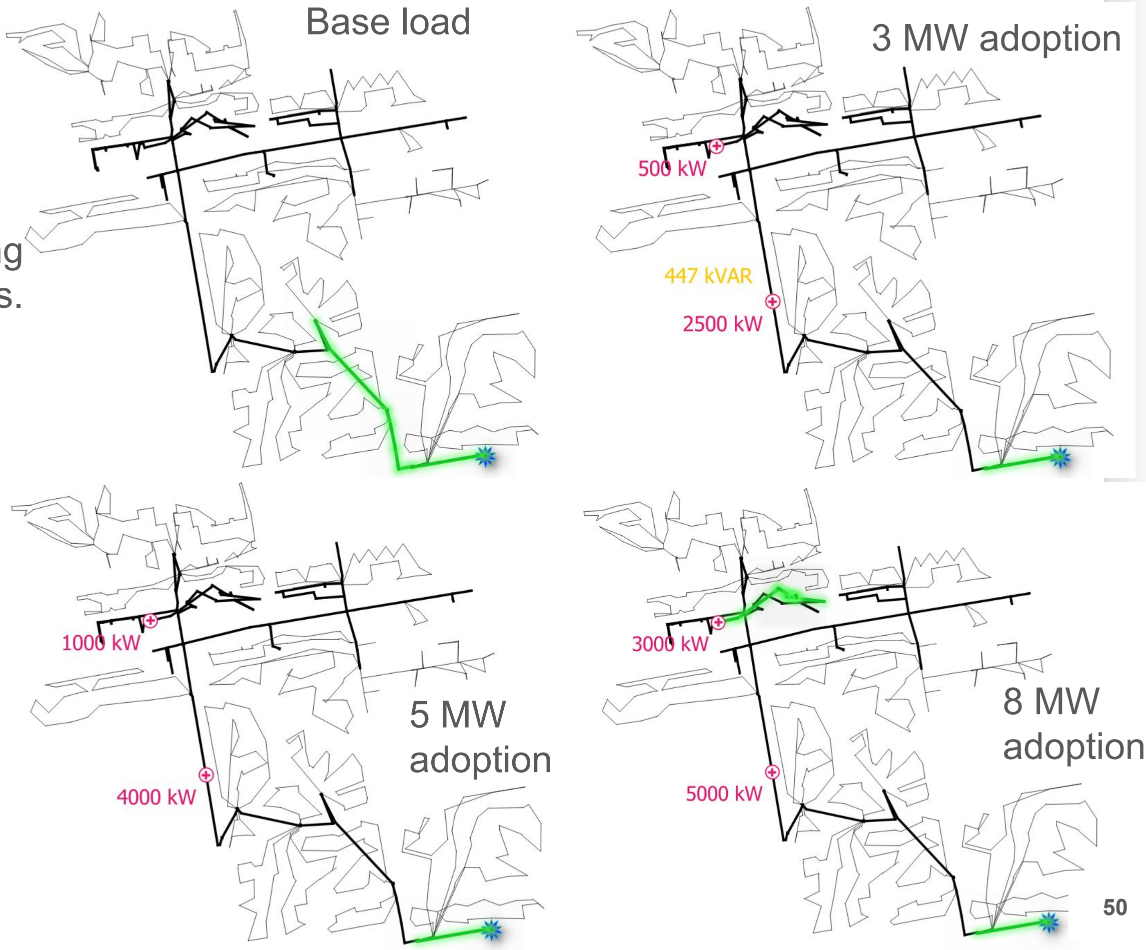


Feeder F012

For all evaluated PV adoption levels, upstream line loading decreases, resulting in deferred investments on those sections.

At 8000 kW adoption, the additional PV capacity at the end location causes overloads on the neighboring lines, requiring additional upgrades.

The **deployment sizing significantly affects the required investments**, with some feeders experiencing added costs related to the non-preferred location



Impact of CS Location on Feeder Costs

As in the cases where PV is deployed in the middle location cases, investment costs increase with higher PV deployment levels (Fig. 1.)

For lower deployment levels, required investments **remain invariant for 69% of the feeders** (Fig. 2.)

However, prioritizing PV at the feeder end results in overall higher costs, indicating that the **middle location is preferred for 57% of the feeders** for high deployment rate

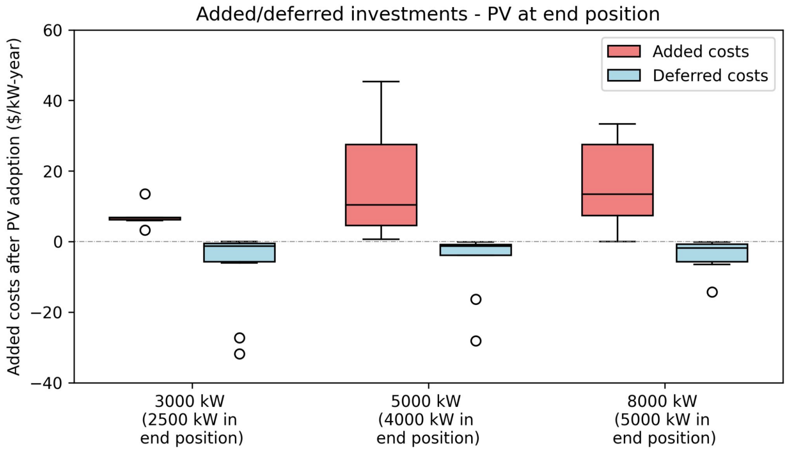
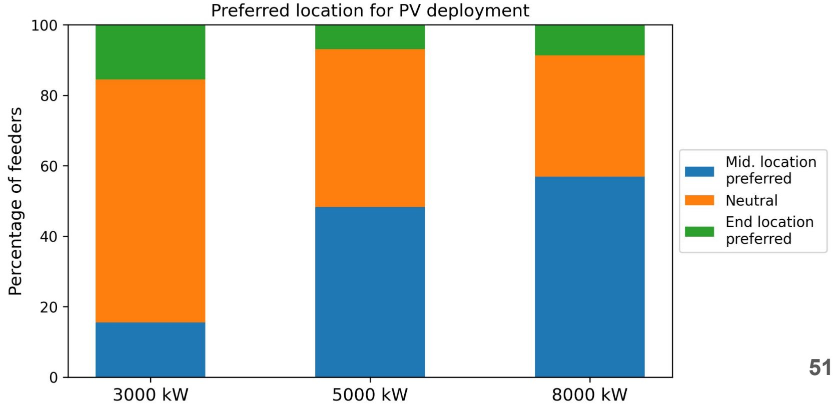


Fig 1. Distribution of added and deferred costs in different scenarios of CS deployment.

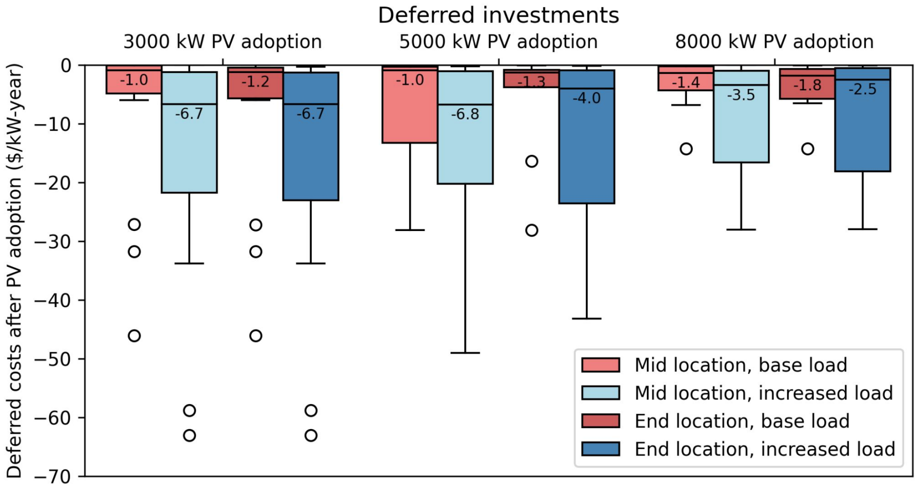
Fig 2. Preferred locations for PV deployment according to the resulting added investments



Deferrals from Combined PV and Load Growth

PV deployment produces significant deferrals, particularly for the 3000–5000 kW level installed at the middle location

Deferrals become more pronounced under increased load, showing that PV has potential to avoid grid upgrades caused by future load



PNM Results:
Effect of Enabling Battery Storage Integration

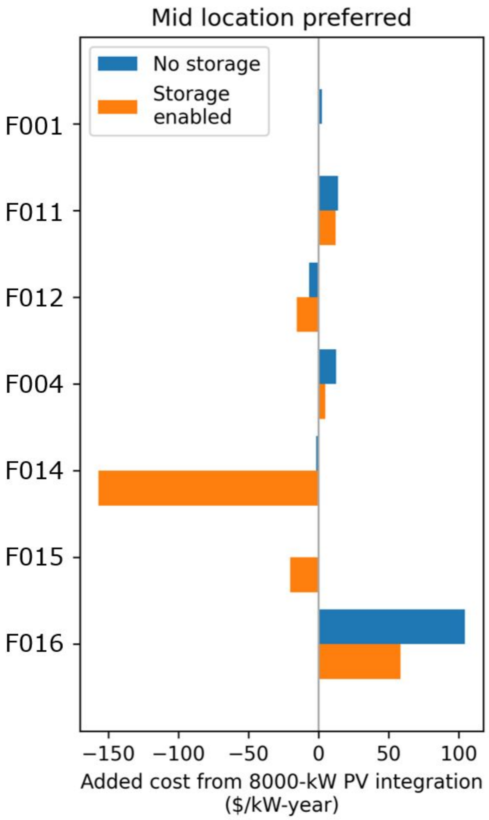
Storage to Reduce Line Loading

Positive values indicate added costs. Negative values correspond to deferred investments

Battery storage (sized between 29 kW and 1899 kW) **defers line reconductoring expenditure** by shifting available energy to high demand hours.

While most feeders see a moderate cost reduction, F014 shows a massive benefit, with **deferred investment savings exceeding $150/kW-year**.

Even in feeders where costs remain positive (like F016), enabling storage drastically lowers the price of PV integration compared to the no-storage baseline.

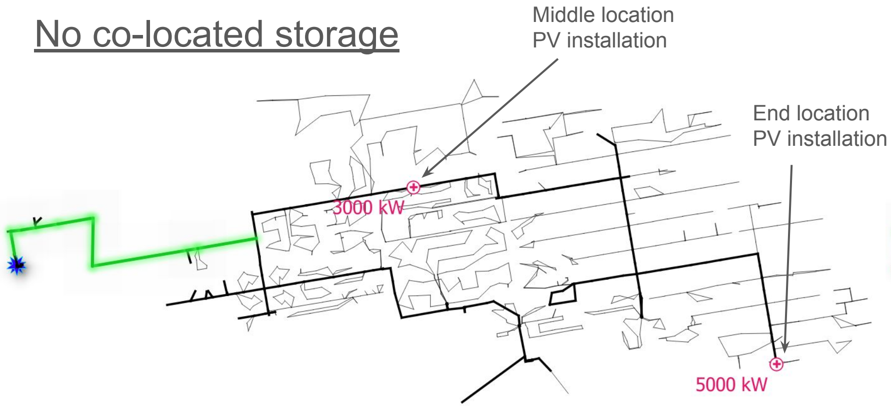


Feeder	Storage size (kW)*
F001	50
F011	85
F012	214
F004	90
F014	1899
F015	29
F016	260

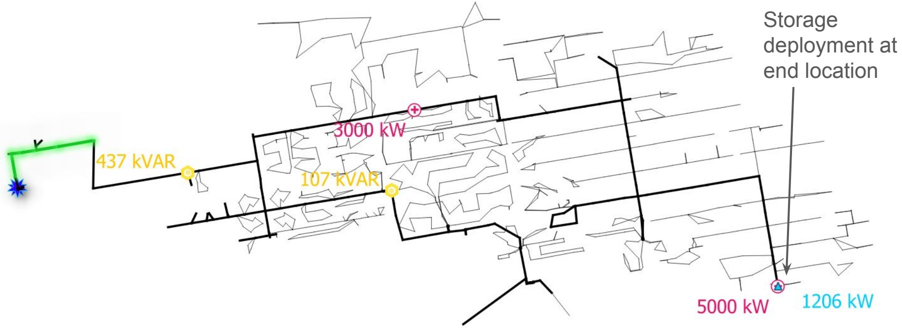
*assuming 2-hour battery for the shown sizes

Example: Feeder F012

<u>No co-located storage</u>



<u>With co-located storage</u>



- Large corridor of overloaded lines from the substation main corridor

When storage is enabled at end location

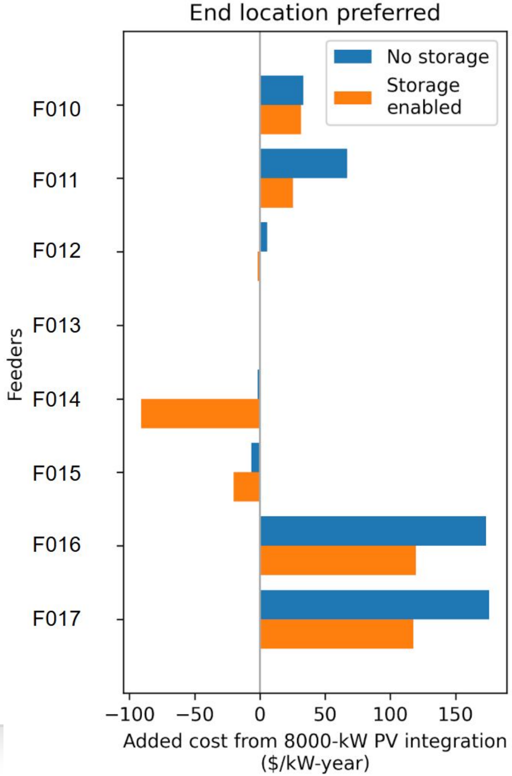
- **Number of affected lines is reduced**
- **58% less investments on line reconductoring**

Storage for PV Integration - End Location

Investment costs related to PV deployment at end locations can be significantly reduced for certain feeders when storage is integrated

F012 investments reverted from added costs to deferrals when batteries are integrated

While deployment at middle location is more cost effective, storage can facilitate PV integration in presence of limitations at middle location (technical, space)



Feeder	Storage size (kW)
F010	33
F011	1300
F012	178
F013	280
F014	1206
F015	17
F016	1762
F017	1329

Conclusions

- Median costs of integrating CS costs are below $6.78/kW of installed solar if PV is installed at intermediate location.
- The choice of distribution feeders for hosting CS strongly affects integration costs. Depending on the feeder, CS deployment can either trigger significant upgrade costs or enable substantial deferral of investments.
- The range of added costs spikes from around $5/kW-year to $45/kW-year as PV deployment increases from 3000 kW to 5000 kW.
- CS deployment is significantly more valuable under high-demand conditions, with median values of $6.7–6.8/kW-year, compared to $1.0–1.8/kW-year under base-load conditions.
- Even on feeders where PV integration costs remained positive, the addition of battery storage diminished those expenses by 20% to 83%.

Impact for the Utility

Statements by Cindy Buck (PNM) during the presentation of the pilot results to the New Mexico Public Regulation Commission on Jan. 29th, 2026:

- **Consistency with Existing Models and Practices:**
  - "*[...] this tool provides data that is consistent with our system impact and our hosting capacity studies that we have done with Synergy.*"
- **Strategic Siting Capabilities:**
  - "*The feeders that were ranked higher in the overall results were the feeders that were heavily loaded and that means that they would have greater hosting capacity. So being able to use this tool to site additional solar in multiple locations could be useful.*"
- **New Perspectives on Generation:**
  - "*[provides] two points of generation on the feeder and additional where batteries might be.*"
- **Optimizing Battery Placement:**
  - "*It does appear to place the batteries in locations that reduces other system improvements due to feeder problems caused by too much solar on the system already.*"
- **Identification of Deferral Potential:**
  - "*The tool is supposed to help identify locations where generation and storage can defer system upgrades. I do think the possibility is there.*"

Results for LPEA

Considerations

Approach:

- Identify the maximum amount of PV that can be installed before causing investments (assuming randomly sited residential growth, 7 kW installations)
- Conduct a substation-based analysis to assess required investments for high PV adoption (up to 200% minimum daytime load (MDL)) and to restrict reverse power flow at the substation

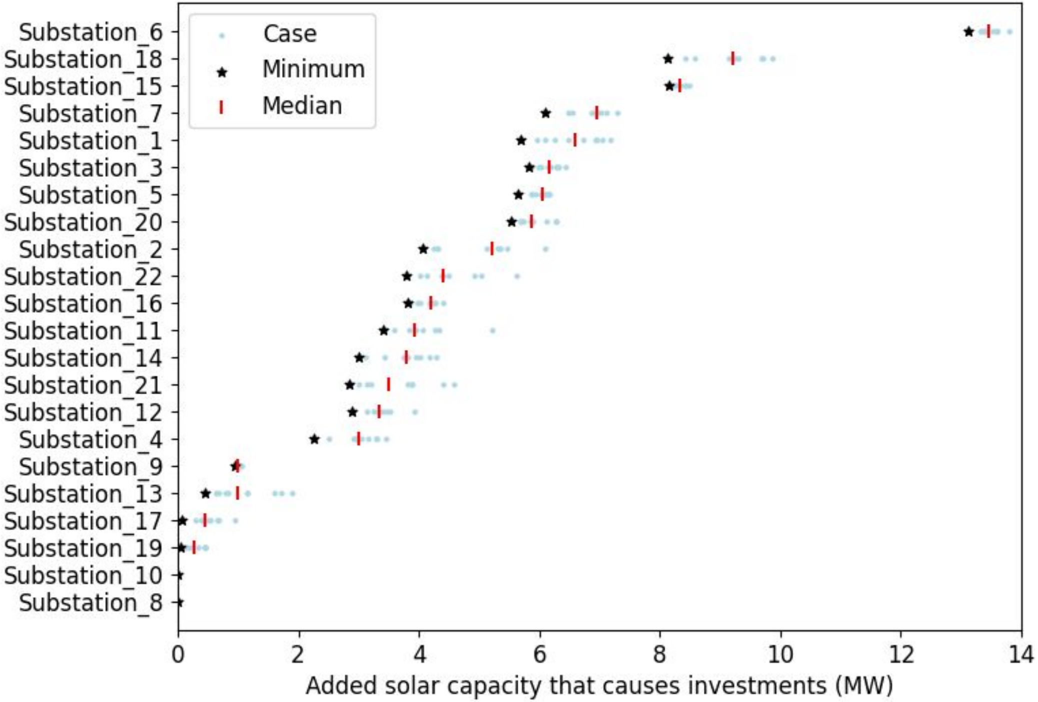
Data:

- 22 substation models in LPEA territory (models that combine all feeders in a substation)
- Customer AMI data from November 2023 to November 2024
- Analyses:
  - **A**: Available capacity for distributed solar
  - **B**: Impact of integrating additional distributed solar up to 200% of Minimum Daytime Load (MDL)
  - **C**: Impacts at levels equivalent to 0, 10, and 50% MDL reverse power flow
  - **D**: Impact of imposing 0 reverse power flow at the substation with storage
  - **E**: Impact of relaxed reverse power flow (10% and 50% MDL) with storage

LPEA Results:
Available Capacity for Zero-cost Distributed PV

PV Capacity at First Investment

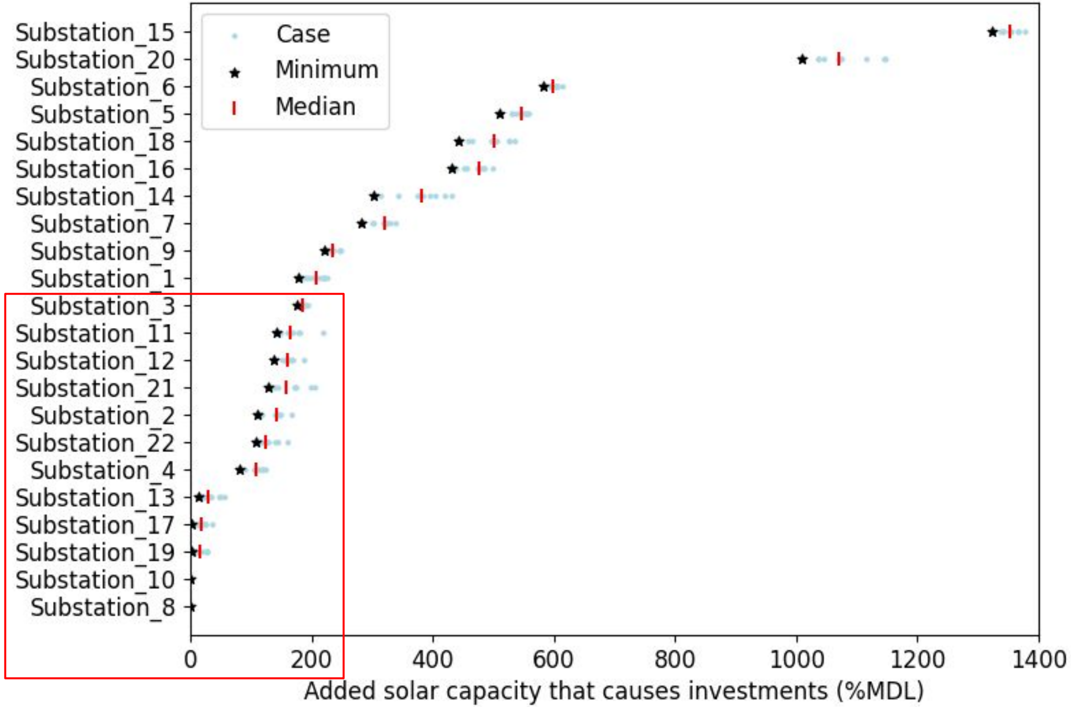
- 10 randomized PV placement cases run per substation.
- **Half of substations** should be able to **add greater than 4 MW** of distributed PV under specified growth conditions.
- Both Substation_8 and Substation_10 have violations in the base case.
- Most substations exhibit **sensitivity to the location** of solar capacity, **indicated by the spread of results**.
  - Maximum spread: Substation_2 - 2.02MW
  - Minimum spread: Substation_9 - 0.11 MW



Relative PV Capacity at First Investment

- Around half of the worst cases have a minimum deployments over or near 200% MDL.

- The spread is not as large in most cases when in context of MDL.



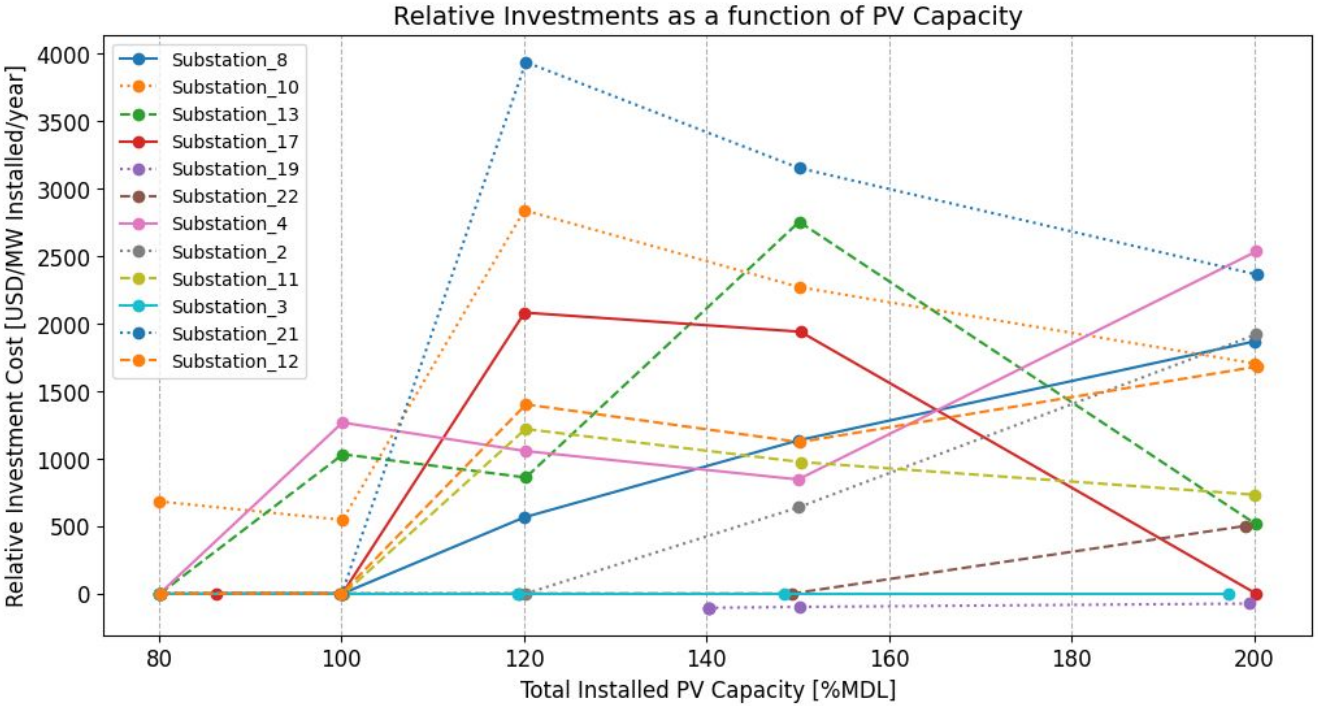
MDL: Minimum daytime load

LPEA Results:

Cost Impacts of Additional Distributed PV

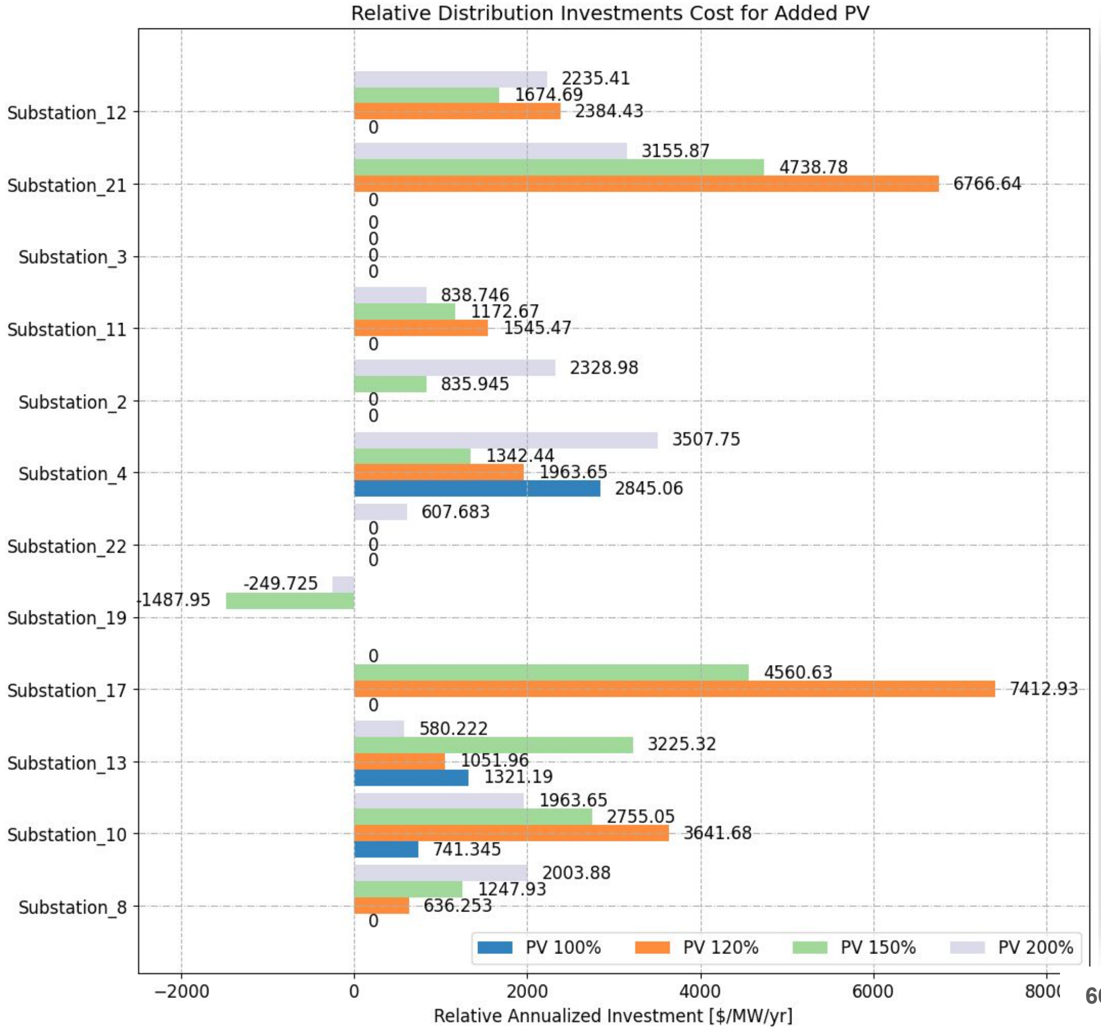
Relative Annualized Investment Cost of PV

- One-time investments see a reduction in relative cost as PV capacity increases
- Limited cases where continuing to add PV results in additional significant investments



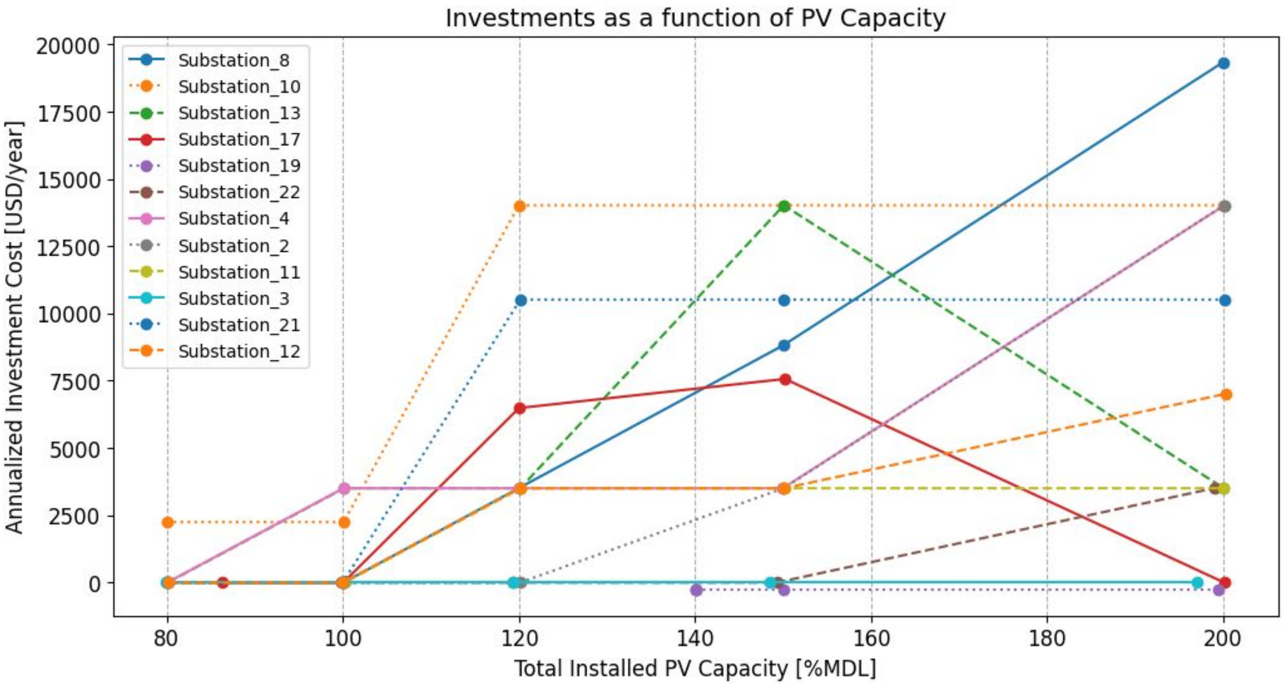
Relative Annualized Cost

- Investments rarely continue to scale with PV as more is deployed
- One time investments have falling relative cost ($/MW) as PV deployment increase



Total Cost of Distributed PV (%MDL)

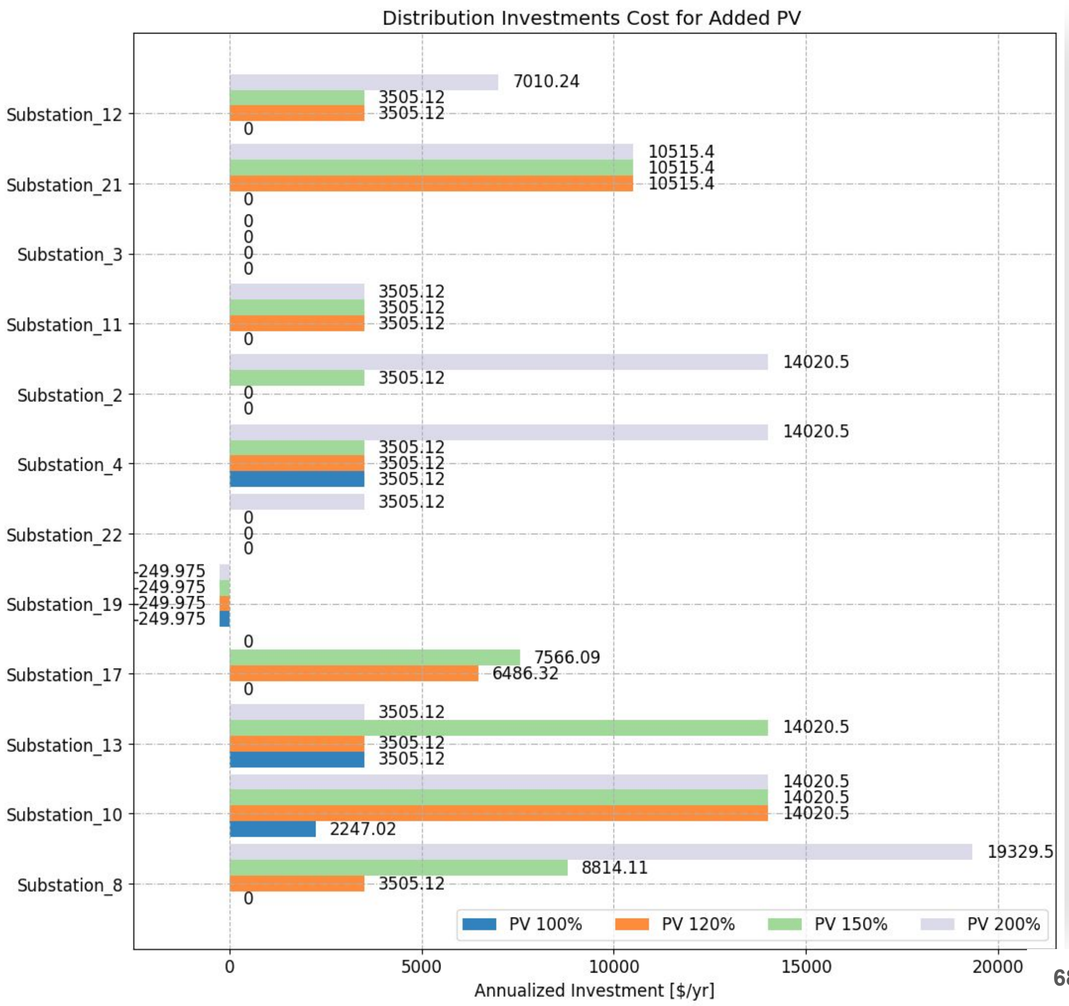
- For most, investments are required for PV capacities between 100 and 125 percent of MDL
- In some instances, **additional PV can** reduce under voltage conditions, which **appear to reduce investments** despite the increase in PV
- Investments are largely in voltage regulators, hence the distinct stratification



Cost of Distributed PV (%MDL)

- Investments in three substations for 100% and 120% MDL PV adoption increase substation hosting capacity, enabling **further deployment without additional investment**

- Substations 2, 4, and 8 are more sensitive to PV adoption and **require voltage regulators** to mitigate overvoltages from PV installations



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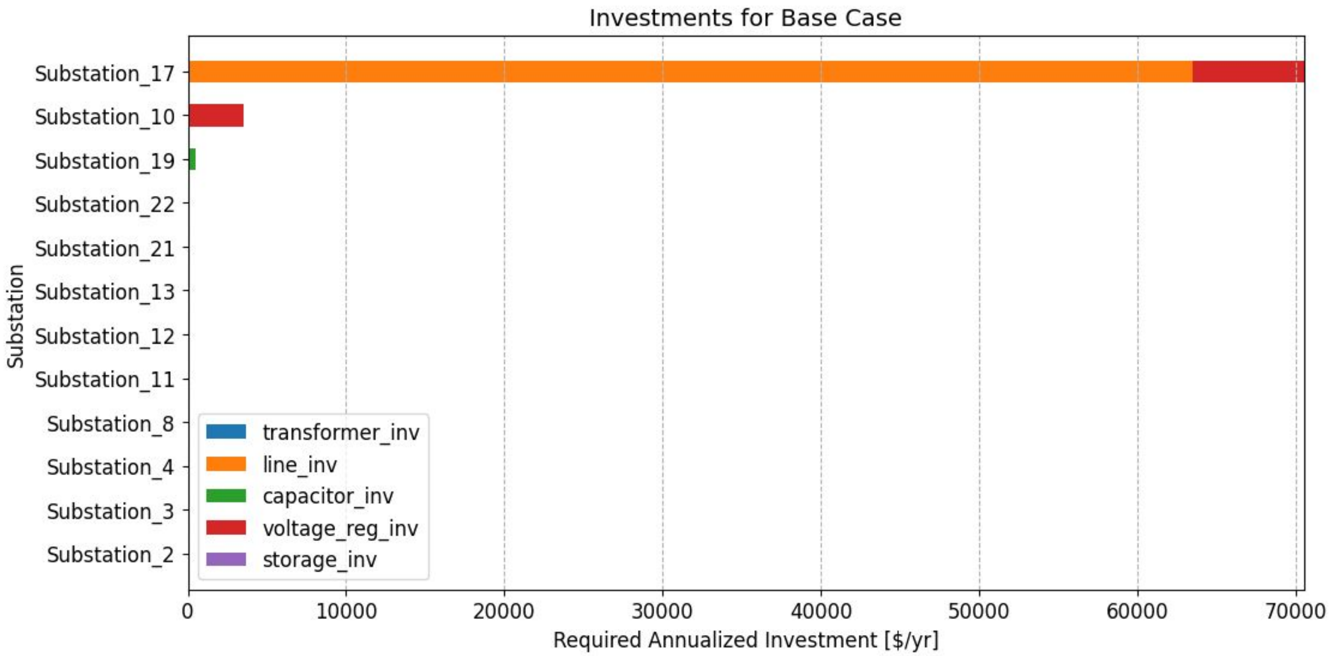
Comparing Costs - Base Case

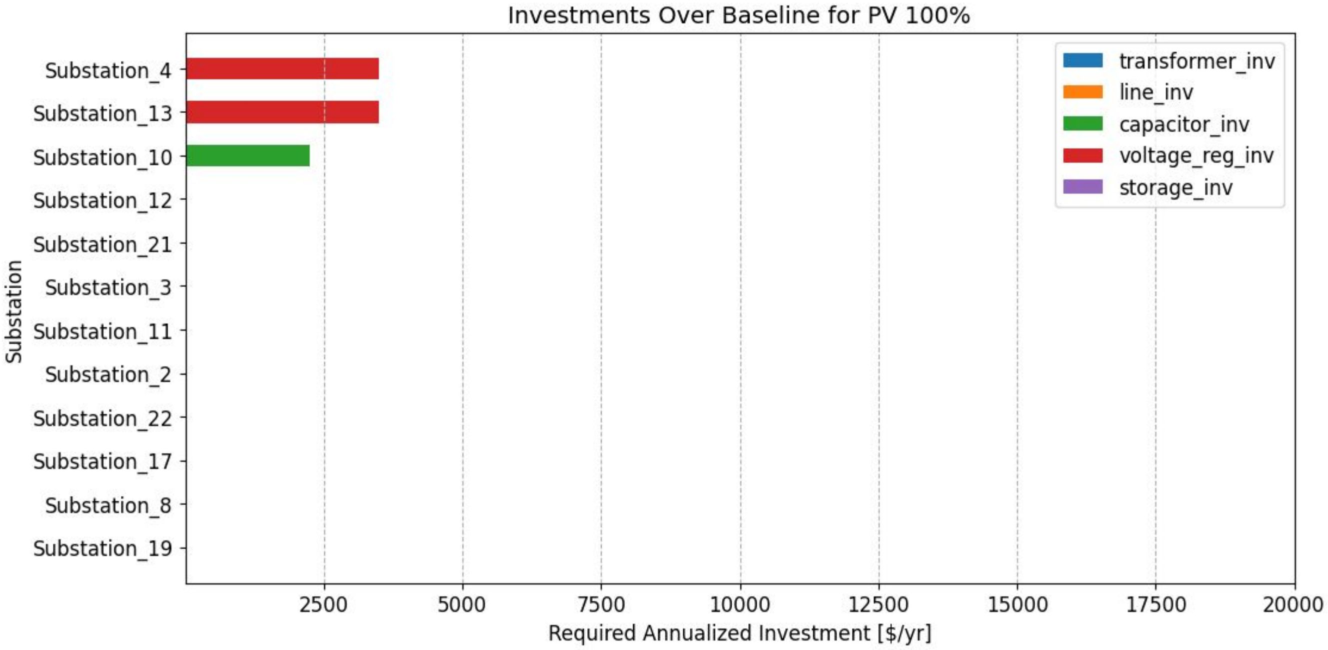
Three of the twelve substations of interest have investments required in the base case, largely caused by **combined under and overvoltage across long sections of the feeders**.



Comparing Costs - 100% MDL

Investments at three substations are needed for 100% MDL adoption.

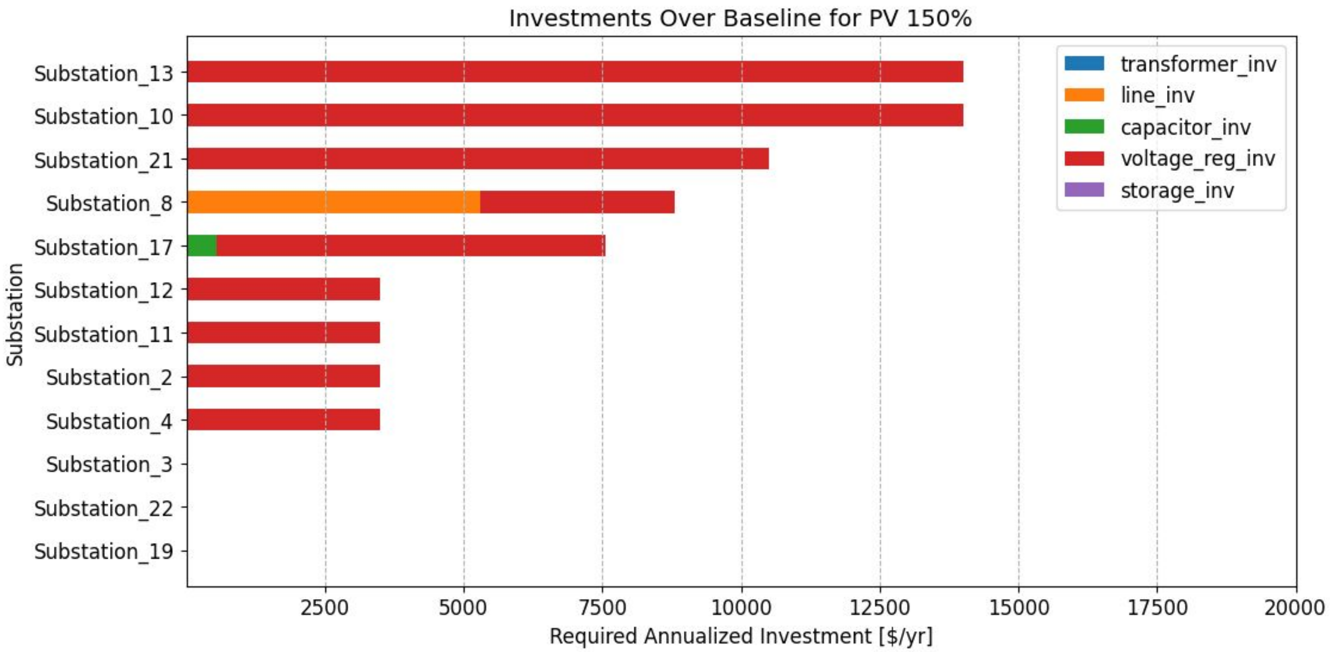
Substation_19 was able to avoid a capacitor needed in the base case due to PV voltage support



Comparing Costs - 150% MDL

Investments significantly increase at 150% MDL.

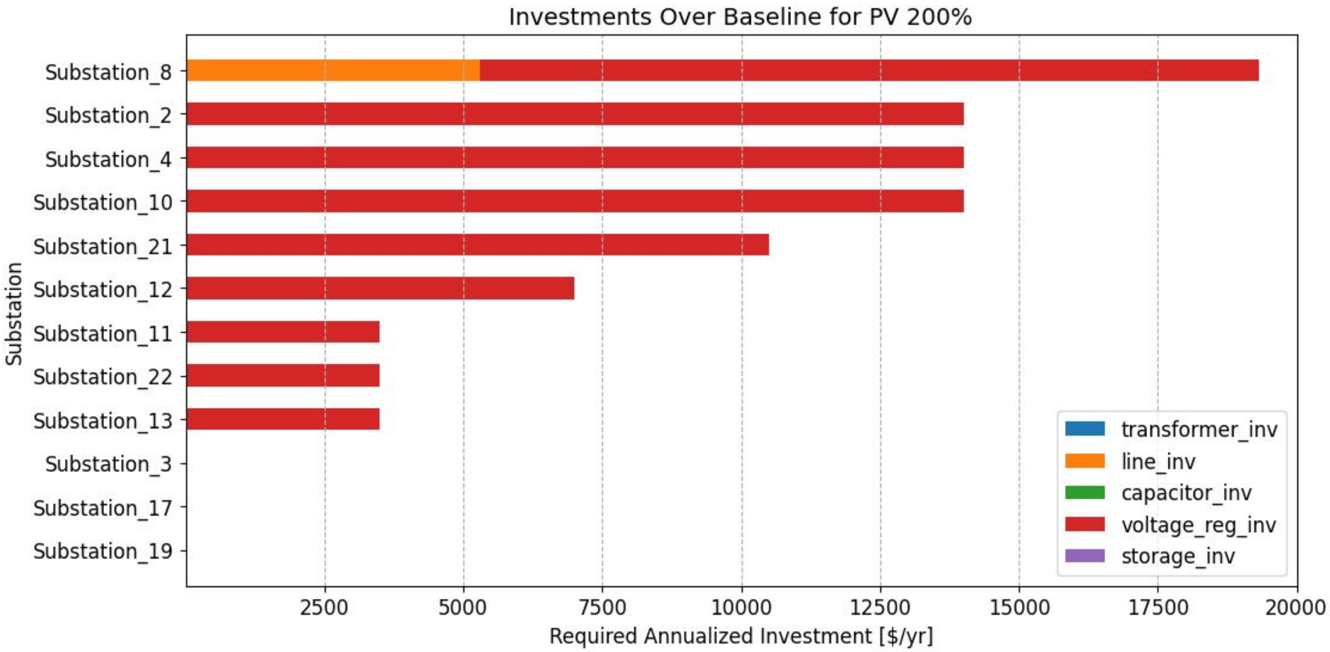
- **Substation_10** exchanged capacitors for voltage regulators
- **Substation_8** needs a line upgrade.



Comparing Costs - 200% MDL

When looking at the incremental cost of additional PV, costs are **dominated by voltage regulators (up to 4)**.

Substation_8 adds more regulators. Despite requiring the most total investment, **Substation_17** does not see PV impacts.

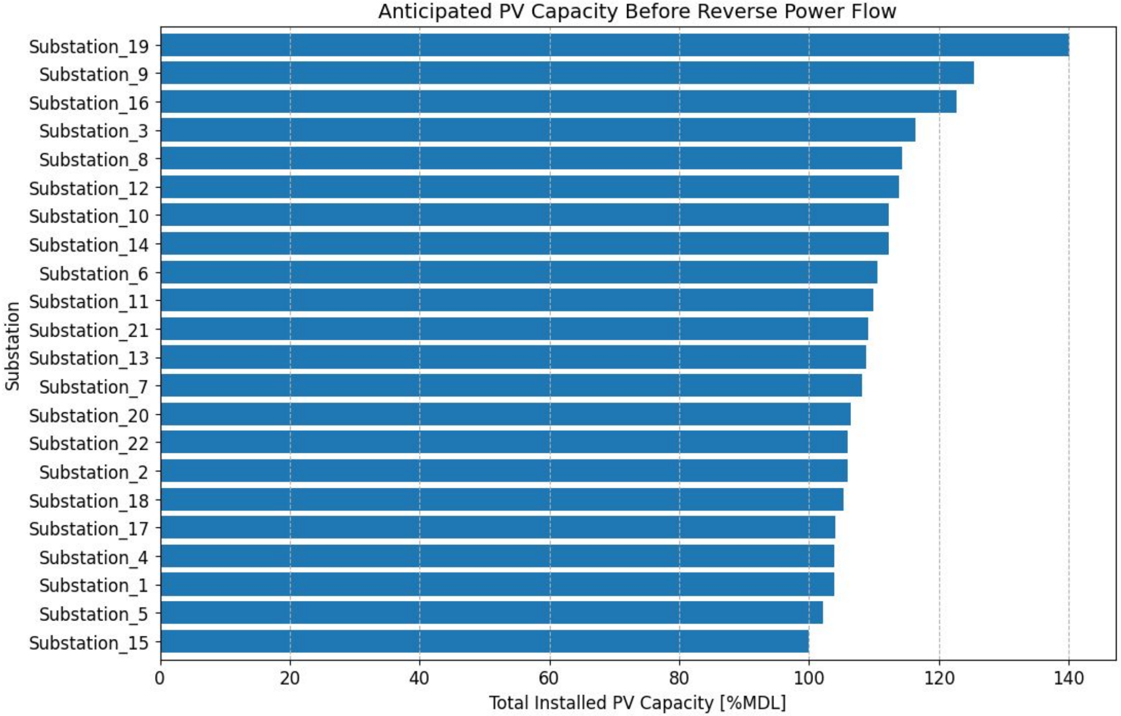


LPEA Results:
Reverse Power Flow Constraint Relaxations and PV Deployment

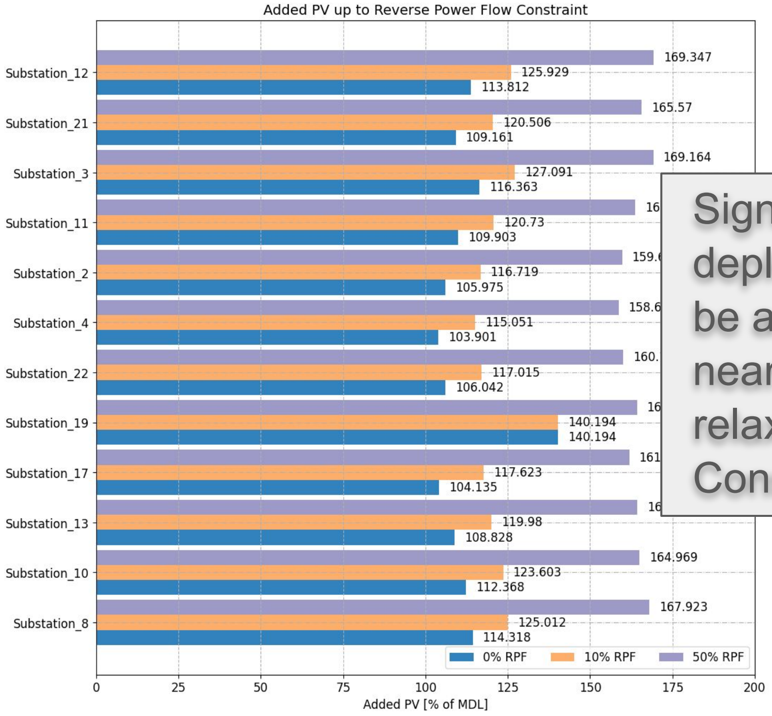
Reverse Power Flow

- Reverse power flow (RPF) often happens before investments are required in these systems.

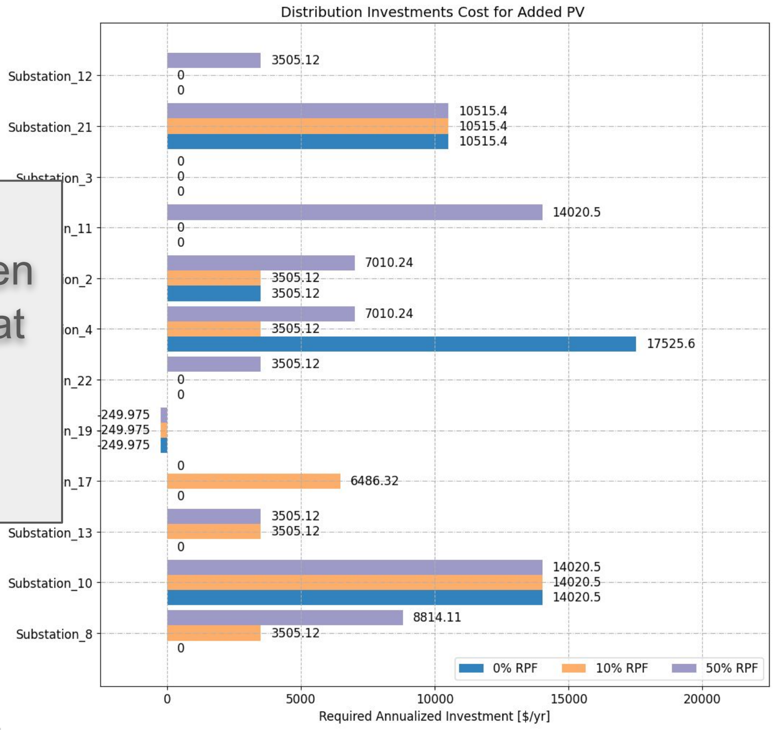
- The hour of MDL and the hour of peak solar production are only aligned in Substation_15.
    - Most substations can host more than 100% MDL in PV capacity due to this misalignment



Cost Impacts of RPF Constraints



Significant PV deployment can often be accommodated at near zero cost by relaxing the RPF Constraint



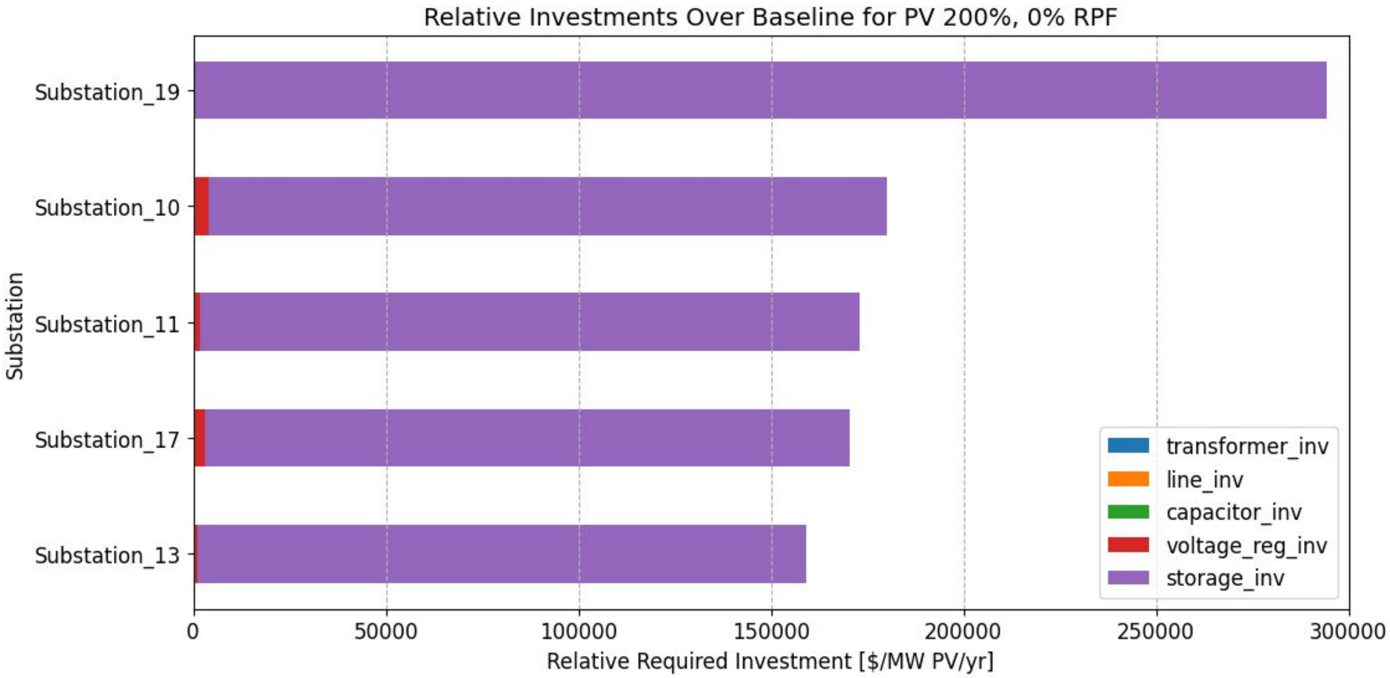
LPEA Results:

Cost of Avoiding Substation Reverse Power Flow with Batteries

Comparing Costs - 200% MDL, 0% RPF

5 substations were identified as possible battery system hosts.

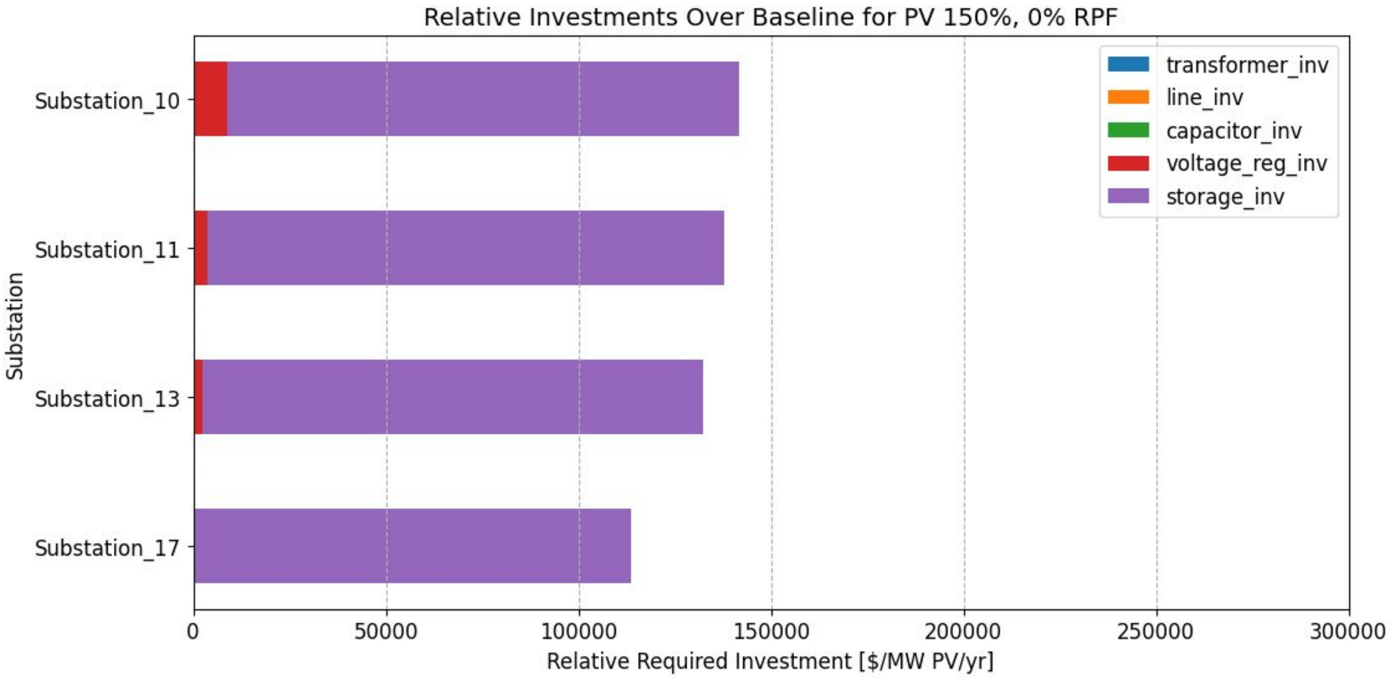
Battery costs dominate all upgrade costs, with a few cases requiring some voltage regulator investment over the base case.



Comparing Costs - 150% MDL, 0% RPF

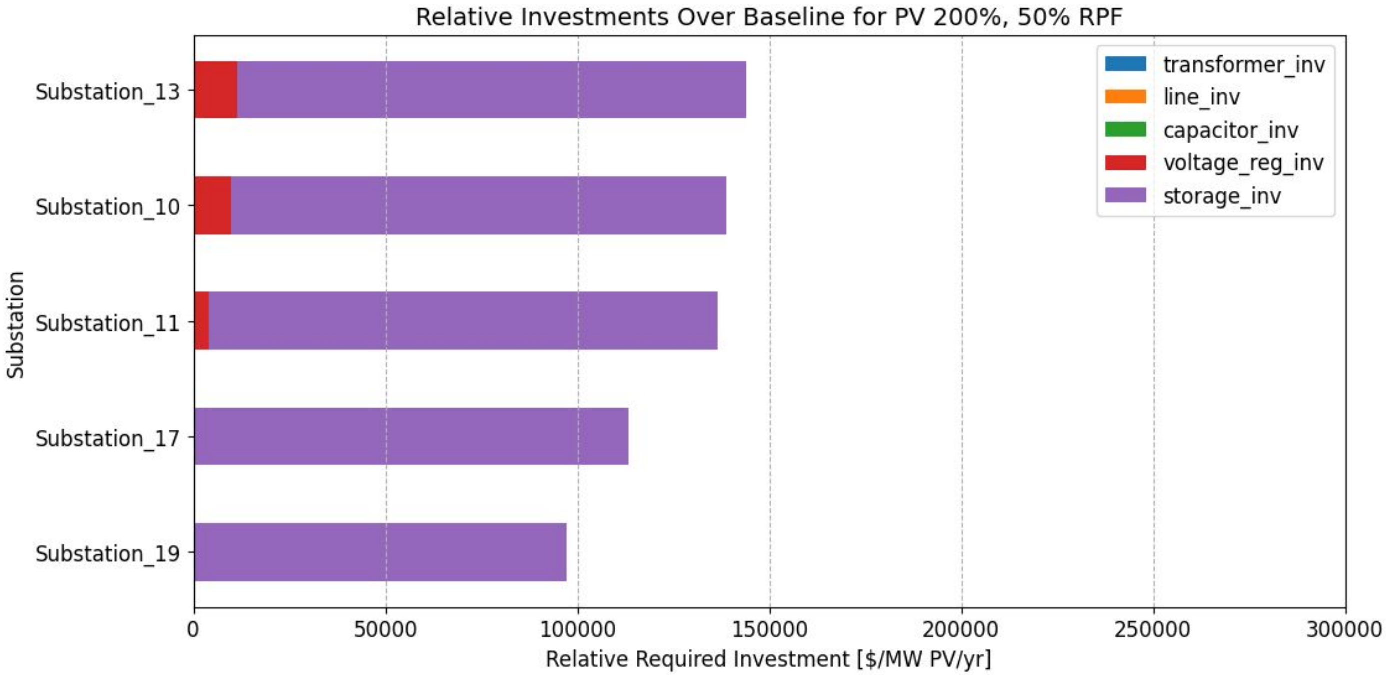
Those relative cost for each MW of PV install drop with the penetration of distributed PV.

Substation_19 was dropped as its relative costs skyrocket because its basecase has reverse power flow.



Cost of 50% RPF Constraint @ 200% MDL

Allowing 50% Reverse power flow, voltage regulator costs go up, but significant reductions in battery capacity bring costs down even at 200% MDL.



Key Findings

- Of the 22 substations evaluated, **nearly half** (10) will likely see **no distribution planning impacts** from additional distributed solar up to 200% of MDL.*
- For most feeders, LODGE identifies potential **over-voltage** conditions that **drive investments** in voltage regulators.
- **Limiting** substation **reverse power flow** can be **expensively** accomplished by batteries, relaxing this constraint results in significant savings

Future use of these results:

- LPEA wants to use this analysis to inform potential investments to face deployment of distributed solar. Planned to present our work to their board to inform decisions on infrastructure upgrades.

* Protection-related upgrade costs are not a part of the scope of this evaluation.

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