Utility Distribution Planning 101

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Distribution system planning has traditionally been focused on maintaining:

- Safety
- Reliability
- Minimum Cost

Distribution planning is key to supporting distribution investment decisions.

As the grid and resource mix are changing, distribution system designs are changing, and distribution system planning is being transformed.

Some states now require regulated utilities provide detailed distribution plans that include:

- Maps with available distributed energy resource (DER) hosting capacity limits and/or desirable zones
- Locational benefits and non-wires alternatives (NWA)

New skill sets may be required as well as coordination across entities within the utility – this includes Electric Distribution Planning departments and often other departments impacted by DER interconnection.
Electric Distribution Planning is a key utility strategy/function that is used to forecast changes within the grid and plan system modifications accordingly, all with a focus on:

**Safety**
- Design and maintain an electric system that does not place the general public nor utility workers at risk

**Reliability**
- Provide the power & energy that homes and businesses need
- Maintain acceptable power quality
  - Maintain stable voltage at point of delivery
  - Support a stable ac frequency (60 Hz)
- Reduce number and duration of electrical outages
  - Frequency (SAIFI) and duration (SAIDI/CAIDI) are tracked

**Cost**
- Supply power and energy at a fair and affordable price
Traditional Areas of Focus for Large Utilities*

Load Forecasting

- Track peak feeder load (SCADA data)
- Publish annual multi-year forecasts
- Evaluate each distribution feeder for annual growth, new loads
- Feeder load forecasts aggregation for substation loading, need for expansion
- Substations may require upgraded or additional transformer banks, transmission, distribution equipment
- System Planning (transmission) uses this to plan transmission upgrades (new lines or higher voltages)
- Substation engineers evaluate the need for larger transformers or additional transformer banks

*Larger utilities often have groups of engineers that focus entirely on distribution planning functions
Traditional Areas of Focus for Larger Utilities - Continued

- Reliability (SAIDI, SAIFI, CAIDI)
  - Maintain minimum reliability metrics
  - PUC/customer complaint resolution
  - Feeder-level protection
  - Under Frequency Load Shedding

- Power quality support

- Voltage support (ANSI C84.1)
  - Capacitor placement
  - Voltage regulator placement

- Evaluation of “special projects” such as large DER systems

- Large distribution project design (e.g., airports, arenas, campuses, etc.)

These traditional planning functions remain, while new challenges and opportunities are emerging.
Question:
How do utility engineers plan their system changes and upgrades?

Answer:
Utility engineers use sophisticated computer-based tools, but there are many types of tools available.

Just a few years ago, prior to computer modeling, engineers relied on chart graphs and spot measurements, and often installed oversized equipment while other equipment burned to the ground. Computer models help utilities “sharpen the pencil.”
Most utilities use a Geospatial Information System (GIS), where they track their distribution lines, transformers, substations, customers, and sometimes the DER (e.g., PV systems).

GIS departments update the GIS data to track system changes, new customers, etc.

Modeling platform users “extract” the GIS data, import that data to the modeling platform, then run the model.

It is critical for utilities to have a high-quality GIS system with accurate data.
**Larger utilities typically use the following:**
- CYMDIST (power flow)
- Synergi (power flow)
- ASPEN (protection)
- DEW (power flow)
- Others….

**Small-medium utilities typically use:**
- Milsoft Windmil (power flow)
- Milsoft Light Table (protection)
- Other software
- Consultants

Modeling software is a large investment in hardware, software, and training; thus utilities are hesitant to change platforms!

Larger utilities have teams of modeling experts, while smaller utilities rely on institutional knowledge or third-party consultants.
Planning Functions: Identify System Risks

- Determine N-0 (system intact overloads) and N-1 (based on one-point of failure) risks based on the peak demand and available capacity

- Other considerations
  - Power Quality (low or high voltage)
  - Reliability (line and equipment exposure)
  - Environmental considerations (e.g. line losses)
  - Safety
  - Legal
  - Financial
Planning Functions: Create Risk Mitigation and Projects

Traditional “poles and wires” solutions to mitigate system risks

- New distribution feeders
- Reconductoring feeders
- New substations
- Expanding substations
- Converting overhead lines to underground
- Replacing aging systems

Source: NREL Pix 08216
Planning Functions: Annual Electric Distribution Budget

Create Annual Capital Budget

- Determine funding by program
- Evaluate Customer Minutes Out (CMO) and value of service reliability
- Determine Cost-Benefit Ratio
- Prioritize projects over a five-year time frame (typical)
- Budget based on corporate guidelines

Example Electric Distribution Budget

<table>
<thead>
<tr>
<th>Program</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Service</td>
<td>19.9%</td>
</tr>
<tr>
<td>Elec Asset Health</td>
<td>11.2%</td>
</tr>
<tr>
<td>Street Lights</td>
<td>2.8%</td>
</tr>
<tr>
<td>Elec Capacity</td>
<td>9.6%</td>
</tr>
<tr>
<td>Elec Mandates</td>
<td>8.4%</td>
</tr>
<tr>
<td>Reliability</td>
<td>16.1%</td>
</tr>
<tr>
<td>Sub Capacity</td>
<td>12.4%</td>
</tr>
<tr>
<td>Sub Asset Health</td>
<td>5.5%</td>
</tr>
<tr>
<td>Equip Purchase</td>
<td>9.7%</td>
</tr>
<tr>
<td>Fleet</td>
<td>2.0%</td>
</tr>
<tr>
<td>Other</td>
<td>2.4%</td>
</tr>
</tbody>
</table>

Note: This complex planning approach may not be used by small and mid-sized utilities, but is important for larger utilities due to the scale of operations and number of customers.
Who Pays?
Construction Allowance vs. DER Mitigation Costs

► Most investor-owned utilities give Construction Allowance for new projects, often resulting in no up-front cost for new construction.
  ■ Investments are generally placed in the utility’s “rate base” and recovered through tariff design.

► Some DERs such as small PV systems may interconnect without system upgrades but are responsible to pay for any upgrades if required to mitigate potential problems.

Source: NREL PIX, Coddington
Basic Questions Related to Utility Distribution Mapping & Modeling

- What GIS platform has the utility invested in?
- How many utility staff focus on the updating (cleaning up) GIS models?
- How accurate is the utility’s GIS data?
- What updates are planned?
  - Adding secondary wires?
  - Adding load points (customers)
  - Adding DERs?
- What is the lag time between construction & system changes and GIS updates?
- Are phases (A-B-C-N) identified correctly?
- Is the GIS system obsolete? What is the cost of any updates or system replacement?

Source: EPRI GIS Interest Group
Basic Questions Related to Utility Distribution Mapping & Modeling

- What *distribution system* power flow modeling platform(s) does the utility use?
- How many utility staff are trained to use this platform?
- What modeling platform is used for protection coordination? (i.e., fuses, circuit breakers)
- How often does the power flow model extract data from the GIS?
- Are DERs tracked/modeled in the GIS or power flow models?
- Is the utility able to model “smart inverter functions”?
- Is the utility working toward an “Easy Button” for DERs?
Consumers Energy Substation Capacity Constraint – A Special Case for Distribution Planning

► Screening criteria for non-wires alternatives (NWA) pilot
  ■ Distribution system upgrade driven by load growth
  ■ Deferrable cost of at least $1 million
  ■ System need at least 2 to 3 years out

Source: Mark Luoma and Steve Fine, Consumers Energy, “Non-Wires Alternatives Lessons and Insights from the Front Lines,” presentation for Peak Load Management Association
Energy Savers Club for Targeted Load Relief

► Swartz Creek substation transformer peak loadings: 92%, 94%, 80%, 79%, and 85%, respectively from 2012 - 2016
  ■ Capacity upgrade was not immediate; time to test NWAs
► Energy Savers Club pilot program to reduce energy load on substation
  ■ Tests role that intentional targeting of EE and DR programs to specific capacity-constrained geographies can play in managing load and deferring capacity-related investments
  ■ Investigates energy efficiency (EE) and demand response (DR) as potential lower-cost solutions
  ■ Relies heavily on existing EE and DR programs
► Uniquely branded marketing campaign within target area (suburban/rural) to connect customers to existing programs
  ■ Energy efficiency – Marketing programs to commercial and industrial customers
  ■ Demand response - Marketing two types of time-varying rates and an AC cycling program to residential customers
► Consumers Energy conducted a second pilot in 2019.

Sources: Consumers Energy’s Electric Distribution Infrastructure Investment Plan (2018-22), March 1, 2018; personal communication with Mark Luoma, Consumers Energy, Oct. 15, 2018; from Lisa Schwartz LBNL

~ Slide courtesy of Lisa Schwartz – Berkeley Lab ~
Integrated Distribution Planning
A Means to Plan for DER Integration
Classes of Distribution Planning Tools

- **Forecasting**
  - DER forecasting
  - Load forecasting

- **Power flow analysis**
  - Peak Capacity Power Flow Study
  - Voltage drop study
  - Ampacity study
  - Contingency and restoration study
  - Reliability study
  - Load profile study
  - Stochastic power flow study
  - Volt/Var study
  - Real-time performance study
  - Time series power flow analysis

- **Power quality analysis**
  - Voltage sag and swell study
  - Harmonics study

- **Fault analysis**
  - Arc flash hazard study
  - Protection coordination study
  - Fault location identification study

- **Dynamic analysis**
  - Long-term dynamics study
  - Electromechanical dynamics study
  - Electromagnetic transients study

- **Advanced optimization**
Load forecasting tools

► Inputs to load forecasting tools
  ◼ Weather, geographic, economic, demographic, DER and demand response data

► Forecasting DER growth requires:
  ◼ DER type, quantity, location, timing and other attributes

► Factors that impact DER forecasting:
  ◼ Historical adoption rates
  ◼ Economic return for the customer
  ◼ Available DER incentives
  ◼ Procurement programs

► Output of load forecasting tools:
  ◼ Load profiles across circuits, banks and subsections of the circuit
  ◼ Necessary temporal and spatial granularity to considering impacts

► Inputs for DER forecasting:
  ◼ Market information (e.g., fuel prices, existing electricity tariff)
  ◼ Customer load information (hourly end use loads)
  ◼ DER technology information (e.g., capital costs, operating and maintenance costs, performance data)
  ◼ Other customer decision factors
Advances in Electric Distribution System Planning (example PV analysis)

- Traditional planning studies have focused on:
  - Capacity planning
  - Cost
  - Safety
- Because of newer technologies deployed at the distribution level, the planning process must change. Capacity is not the only factor to consider.
- As an example, the future deployment of small-scale residential solar cannot be predicted. The planning process must take into account this uncertainty.
- 15 prototypical circuits were used to examine the larger parent population of Southern California Edison (SCE) circuits.
- The following is an example process that SCE developed as part of California Solar Initiative #4.
Determining Native PV Limits of a Circuit

- **Step 1** - Define key metrics: what is, and what is not, an operational limit that would prevent the deployment of additional solar (utility dependent).
- **Step 2** - Clear base case models of violations: Developed time-series models of representative circuits. The base condition must be free of violations.
- **Step 3** - Deploy Monte-Carlo PV adoption models: A socio-economic PV adoption model provides different “likely” future scenarios for each circuit.
- **Step 4** - Run simulations on various scenarios to determine the native PV limit for the circuit. In this case, 50 simulations were conducted at each penetration level.

<table>
<thead>
<tr>
<th>Violation #</th>
<th>Violation</th>
<th>Violation Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Thermal Overloads</td>
<td>Limit: Exceeding any device thermal limit, 100% rating (200% for secondary service transformers)</td>
</tr>
<tr>
<td>2</td>
<td>High Instant Voltage</td>
<td>Limit: Any instantaneous voltage over 1.10 p.u. at any point in the system.</td>
</tr>
<tr>
<td>3</td>
<td>5 min ANSI Violation</td>
<td>Limit: ANSI C84.1: 0.95&gt;V&gt;1.05 p.u. for 5 minutes at &gt;10% of meters in the system.</td>
</tr>
<tr>
<td>4</td>
<td>Moderate Reverse Power</td>
<td>Warning: Any reverse power that exceeds 50% of the minimum trip setting of the substation breaker or a recloser. (Requires analysis of protection coordination)</td>
</tr>
<tr>
<td>5</td>
<td>High Reverse Power</td>
<td>Limit: Any reverse power that exceeds 75% of the minimum trip setting of the substation breaker or a recloser.</td>
</tr>
<tr>
<td>6</td>
<td>Voltage Flicker</td>
<td>Limit: any voltage change at a PV point of common coupling that is greater than 5% between two one-minute simulation time-steps. (Adapted from the Voltage fluctuation design limits, May 1994)</td>
</tr>
<tr>
<td>7</td>
<td>Voltage Drop/Rise on Secondary</td>
<td>Limit: 3V drop or 5V rise across the secondary distribution system (Defined as the high side of the service transformer to the customer meter)</td>
</tr>
<tr>
<td>8</td>
<td>Low Average PF</td>
<td>Warning: Average circuit power factor &lt;0.85 (Measured at substation)</td>
</tr>
<tr>
<td>9</td>
<td>Circuit Plan Loading Limit</td>
<td>Warning: Nameplate solar exceeds 10MVA for a 12 kV circuit, 13 MVA for a 16 kV circuit, or 32 MVA for a 33 kV circuit.</td>
</tr>
<tr>
<td>10</td>
<td>High Short Circuit Contribution</td>
<td>Warning: Total short circuit contribution from downstream generation not to exceed 87.5% of substation circuit breaker rating</td>
</tr>
</tbody>
</table>
For each circuit, 4,000 time-series simulations are conducted.
- At each penetration level there are 50 simulations conducted
- Penetration levels at 5% are examined
- Each simulation is a different adoption scenario of solar

The results of these simulations are distilled into a single plot for each circuit. Example shown at right.

The plot can then be used to determine the native limit, and to identify what the limiting factors are.

The plot forms a basis to determine how to support higher penetration levels of PV, and which technologies might enable this.
Each of the native limits can be avoided through circuit upgrades.

Traditional methods:
- Adjustment of existing voltage regulators
- Installation of voltage regulators
- Adjustment of existing capacitors
- Reconductoring secondary segment
- Reconductoring primary segment

Advanced technologies
- Fixed pf PV inverters
- Advanced inverter control (CES Rule 21)
- Centralized battery storage
- Behind the meter battery storage

The simulation provides the basis for selecting the best mitigating technologies, but there are many.
Determining Native PV Limits of a Circuit (Key Lessons Learned)

► Most SCE circuits could support 100% penetration of PV once the proper mitigation strategies have been applied.

► Nearly 50% of SCE circuits can host less than 50% PV, while approximately 40% can host less than 25% PV.

► Determining how to achieve 100% penetration on legacy circuits can be challenging, with a mitigation leading to new violations (domino effect).

► The most common violations experienced were power factor and voltage based.

► Proper sizing of secondary drops when new solar is installed is essential.
Does the utility use any type of “Hosting Capacity” metrics on distribution circuits?

Are there defined limits of DER hosting capacity based on location, load, voltage or just policy?

**Hosting Capacity Analysis - Questions**

<table>
<thead>
<tr>
<th>Minimum Hosting Capacity</th>
<th>Maximum Hosting Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>C</td>
</tr>
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</table>

**Worst-Case Result for Each Unique PV Deployment**

- **A** – All penetrations in this region are acceptable, regardless of location
- **B** – Some penetrations in this region are acceptable, site specific
- **C** – No penetrations in this region are acceptable, regardless of location

Source: EPRI
Does the utility pursue a Volt-VAr Optimization (VVO) strategy?
- If so, how do they use power flow models to assist them?
- Does a VVO strategy impact the operation of other devices such as capacitors, voltage regulators, or substation load tap changers (LTCs)? If so, do the models allow that to be simulated?

Source: NEMA “The Value of Volt/VAr Technologies”
Summary of practices at advanced utilities

- Performing detailed load and DER forecasts, by location
- Conducting hosting capacity studies for some or all feeders and making information publicly available via online maps
- Systematically considering non-wires alternatives (NWA) to traditional distribution system investments – developing NWA suitability criteria
- Investing in automation, communication and information technology improvements to provide greater visibility and flexibility and enable greater levels of DERs
- Looking at value components of DERs by location and incorporating into tariffs. Value components include:
  - Energy
  - Capacity
  - Environmental
  - Demand reduction and system relief

*From New York REV Value Stack tariff
Discussion and Questions
Thank You for Coming!