DER Impacts to Urban Utilities

Study Summary

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Executive Summary

This report summarizes the projected technical impacts of distributed customer-owned energy systems in EPCOR's distribution system. Three classes of DERs (distributed energy resources) – solar photovoltaics, battery energy storage, and electric vehicles, are considered for varying levels of electric-utility customer uptake from 10% to 100%. Time series simulation of solar insolation, battery storage system behavior, and EV (electric vehicle) charging behaviors were used to determine worst-case starting conditions for a stochastic approach to simulate impacts of widespread DER into multiple utility-provided distribution circuit models. Modes of operation/impact examined in the analysis include voltage quality and distribution infrastructure capacity. Where possible, realistic deployments of DER equipment were assigned by the stochastic algorithm, based on market-available equipment and customer load size.

In total, 39 utility circuit models were studied for 25kV and 15kV urban distribution circuits. The analysis indicates that EDTI's distribution system (a dense urban utility, with short, high-capacity circuits) has fairly high headroom capacity for PV uptake, up to 60% customer penetration, but a low capacity for EV charging uptake, up to 15% penetration, before operating or infrastructure adjustments must be made.

Modeling of customer owned-energy storage systems such as batteries did not show an advantage for improving penetration of PV systems, as battery charging drove under-voltage risk at the same penetration level as the PV overvoltage outliers, at 60% penetration. These results indicate that urban utilities such as EDTI should place near-term focus into mitigating the impact from, or increase their ability to accommodate, EV charging.

Introduction

EPCOR Distribution and transmission, Inc. (EDTI) clearly recognizes that along with the benefits of modern technologies like distributed generation, energy storage systems, and electric vehicles, new sets of technical challenges will be introduced. These challenges have the potential to put significant stress on the existing distribution grid simply because the basic assumptions under which the distribution grids (anywhere around the world) were designed and operated for the past hundred years and more are no longer valid.

In order to prepare to meet these challenges, EDTI has initiated in 2015 a comprehensive study on the impacts of distributed energy resources (DER) [1] in its distribution network, which was finalized in June 2018. The study, co-sponsored by the Natural Sciences and Engineering Research Council (NSERC), was conducted by a research team from University of Alberta (U of A).

This document summarizes the main aspects and findings of the study in a compact manner, from the perspective of a non-expert audience.

Background – Overview of Different DER Behaviors in Distribution Systems

Adoption of DER technology may cause voltage quality problems. As noted in [2, p. 275], the voltage drop along a circuit can be represented as:

$$V_{drop} = |V_s| - |V_r| \approx I_R \cdot R + I_X \cdot X, \qquad (1)$$

where

- V_{drop} is the voltage drop along the feeder, in [V]
- V_s is the voltage at the sending side of the feeder (here this will be treated as the substation), in [V]
- V_r is the voltage at the receiving side of the feeder (here this will be treated as the customer, at the end of the feeder), in [V]
- R is the feeder resistance, in [Ω]
- X is the feeder reactance, in [Ω]
- I_R is the feeder current due to active power flow (in phase with the voltage), in [A]
- I_X is the feeder current due to reactive power flow (90° out of phase with the voltage), in [A]

Assuming zero or negligible reactive component, I_X, this formula simplifies to:

$$V_{drop} \approx I_R \cdot R \qquad (2)$$

The interpretation of this simple relationship can be interpreted as follows:

"*For a given fixed infrastructure (R), the amount of voltage drop on a distribution circuit is dominated (negligible* I_X*) and proportional to the amount of load (*I_R*) on that circuit.*"

(Please note - reactive component effects are definitely not negligible in high-power, high voltage systems such as transmission systems. However, this assumption is reasonable for distribution systems with high power factors. Reactive power, in context of urban distribution systems, is discussed more fully in the results and discussion portions of this report.)

To understand the expected impact of different kinds of DER, one only has to consider how they impact the load present on the distribution system. For example, DG systems (such as PV systems) will reduce site load (from the perspective of the power system) as they begin to generate; as their production outstrips the local load, they will push real power into the power system. This power injection (negative I_R) will then cause voltage *rise* along the circuit:

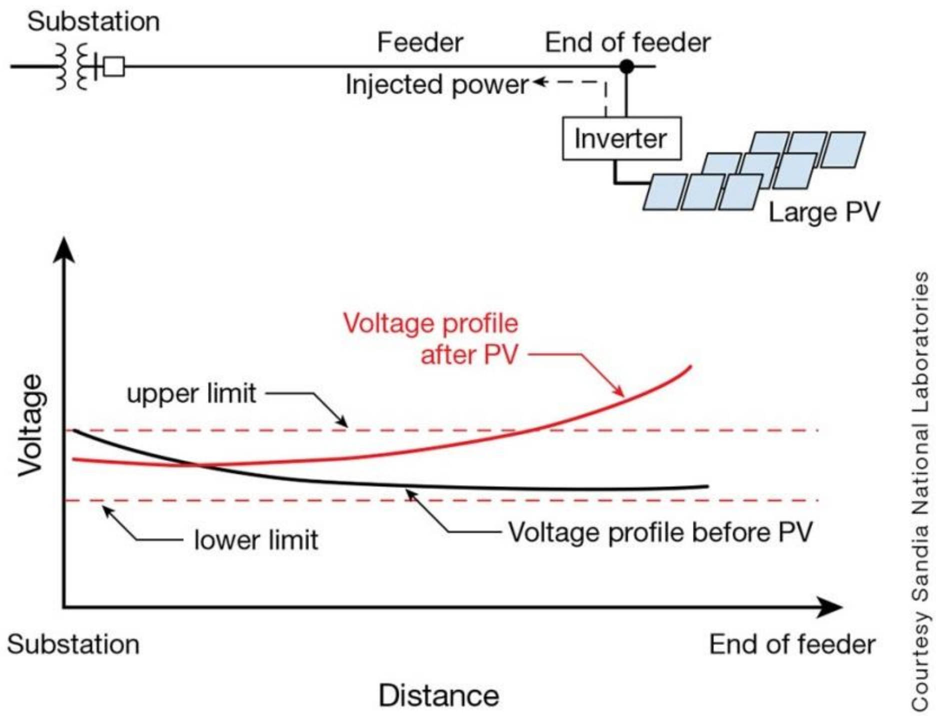

Figure 1: Typical effect of PV power injection on circuit voltage profile. In this generalized case, the power injection of the DG system pushes a portion of the voltage profile into an unacceptably high range

Behaviors of other types of DER further complicate this picture:

- ES (batteries): can both inject power (battery discharging) into the power grid) causing voltage rise, or add to the load already present (charging), creating a *larger* drop in voltage than anticipated. Batteries may charge / discharge at different times of day depending on a battery control scheme;
- Electric vehicle charging adds to I_R, creating a larger drop in voltage than anticipated; in addition, charging may overlap with the existing peak load.

In a many-branched feeder with many loads distributed along it, the above principles hold true, but reasonable predictability is complicated by the number of possible permutations of loading, locations & sizes, and production/behavior of DG or DER systems in real-life distribution systems.

For this reason, the methodology presented in this study was specifically designed to capture possible behavior *envelopes* using statistical analysis that takes into account as realistic as possible deployments of DERs in the EDTI service area in Edmonton.

Using this methodology, a representative sample of the EDTI power system was studied, and key results on the issues from high DER uptake in the EDTI system have been determined. The following sections present this methodology and discuss the key findings from the analysis of the results from a power utility perspective.

Methodology Used in This Study

This study has been explicitly aimed at modeling realistic potential future outcomes in the EPCOR distribution grid (see Table 1). This has been achieved by:

- using real data – using pre-existing detailed EDTI grid models, along with the available historical metering data;
- utilizing the EDTI in-house simulation software which is used by the System Planning department;
- modelling market-available DER equipment.

Another key aspect of this study, which is usually overlooked, is the inherent uncertainty of where and how much DER capacity will be installed. In order to ensure confidence in the study results, this issue has been approached using stochastic Monte Carlo analysis in which DERs along a given feeder are randomly allocated, while respecting certain technical limitations. Then, for each DER penetration level (from 10 %, up to 100 % penetration of customers, in 10 % increments), this process has been repeated so that convergence and statistical significance are ensured. Overall, more than 120,000 individual simulation runs have been conducted over the course of this study.

The detailed analysis has been performed on 39 distribution circuits containing residential, light commercial, and industrial loads (representing approximately one quarter of EDTI's distribution grid with these types of load), identified as representative. The study has concentrated on the impacts on the voltage quality (over- and under-voltage) and infrastructure capacity (power lines and transformers loading) for the following three classes of customer-owned DER:

- DG: Distributed Generation (i.e. solar PV);
- ES: Energy Storage (i.e. batteries);
- EV: Electric Vehicles (in terms of charging).

Table 1. Key Inputs and Assumptions in the Study

DER Technology	*PV*	*ES*	*EV*
Location	Randomly assigned by Algorithm, based on Customer Type		
Size (kW or KWhr)	Randomly assigned in 5kW steps, up to individual customer peak load determined through metering data	Randomly assigned market-available ES (e.g. Tesla PowerWall)	Based on Real Market available EVs
Modelled Behavior	Production was assigned based on a Solar Insolation Study of the Edmonton Area. Circuit simulations assume minimum circuit loading and maximum possible production.	Based on market rate & real-life algorithms. Simulations included different periods of day in a 24hr cycle to capture worst case charging and discharging states + PV peak production	Based on traffic simulation of Edmonton & market rate. Maximum circuit load & peak charging time assumed.

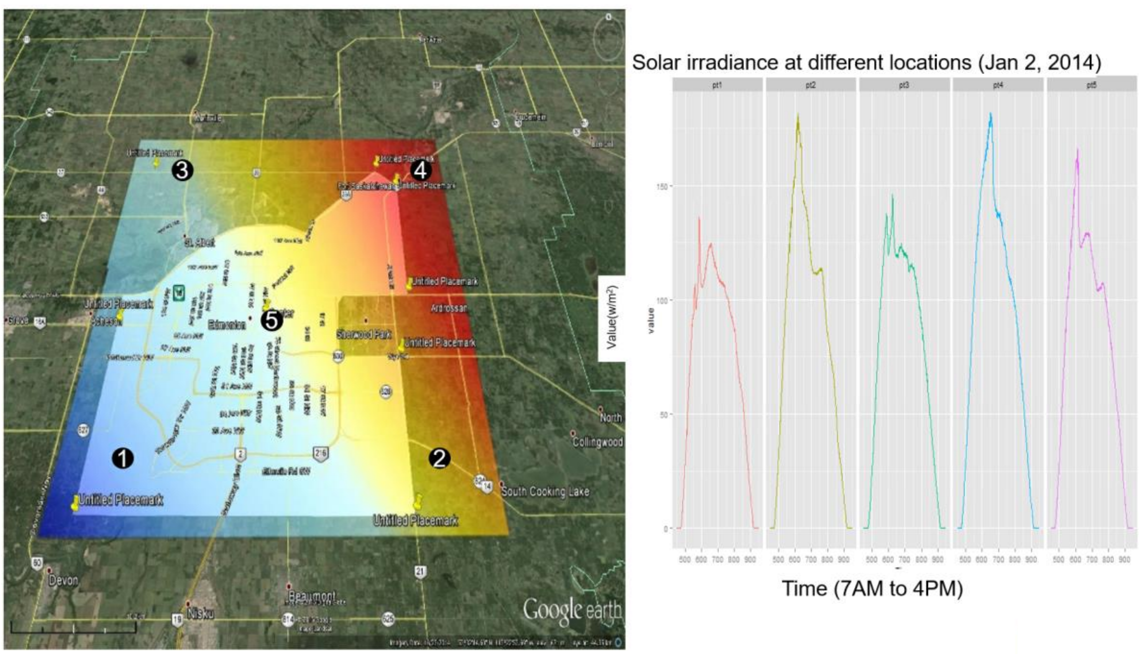

Figure 2: Sample from solar insolation study of Edmonton

The algorithm used to iterate through different scenarios and different penetration levels of DER technology on a circuit-by-circuit basis is shown below:

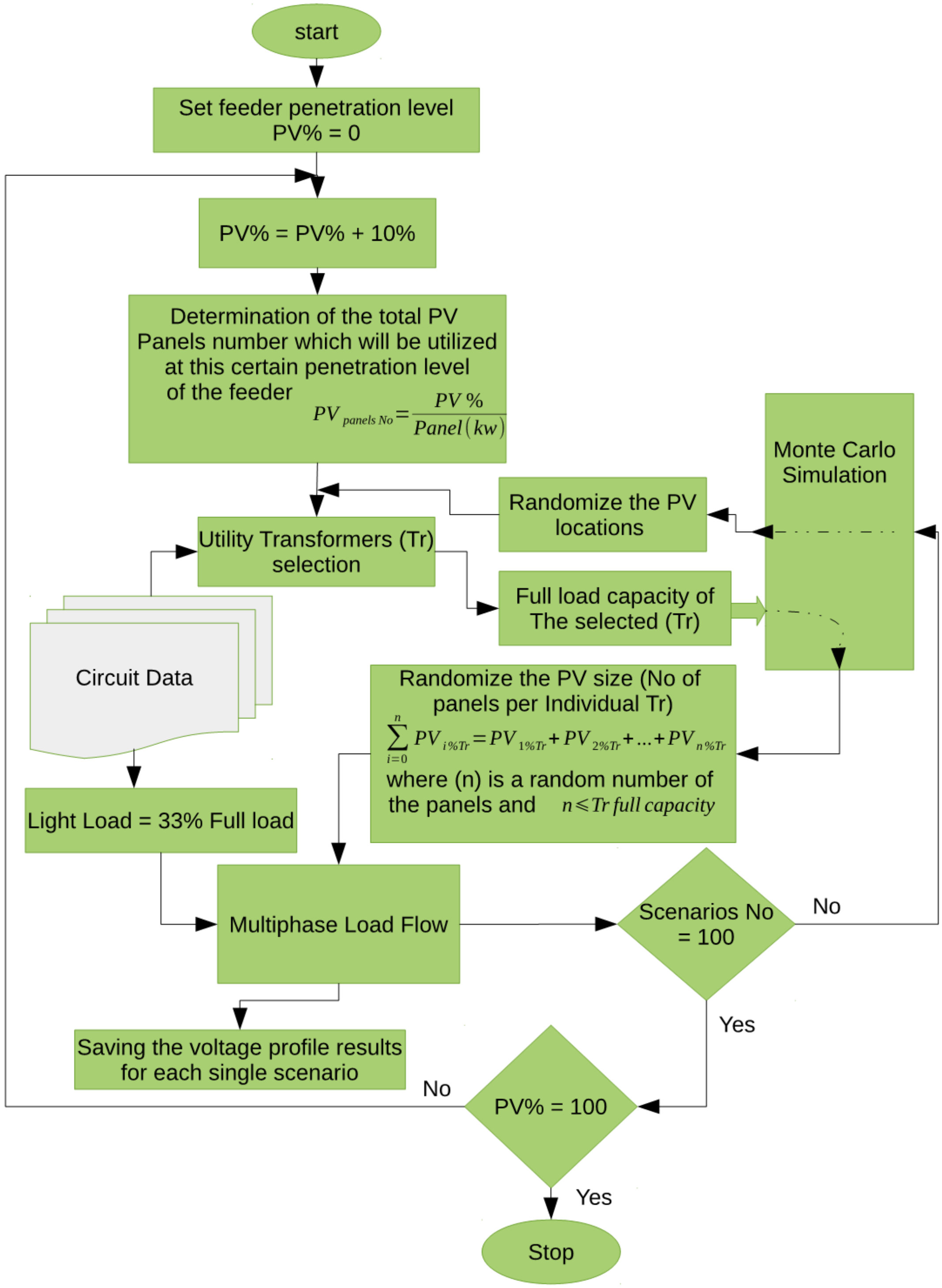

Figure 3: Monte Carlo algorithm to iterate from 10% penetration of PV systems to 100% penetration on a circuit (adopted from [1])

To evaluate the steady-state impacts of these technologies on EDTI's distribution facilities, the simulated voltage results at several points along each modelled distribution circuit have been benchmarked against EDTI's preferred voltage service limits shown in Table 2. These values represent the range of acceptable limits under the ‘extreme operating conditions’ header (per CSA CAN3-235-83).

Table 2. EDTI’s Preferred Voltage Level Limits (120V Customer)

	On a 120V base	Extreme Operating Conditions			
			Normal Operating Conditions		
Service Entrance	Three Phase	110	112	125	127
Service Entrance	Single Phase	106	110	125	127

Another interpretation of the above limits is that EDTI *must* maintain single phase customers between **0.88 – 1.06** of the target voltage level, and *prefers* to maintain these customers between **0.92 – 1.04** of the target voltage level (to ensure compliance with the CSA limits). For this reason, EDTI typically sets its substation load-tap-changer (LTC) at **1.03 - 1.04** of the nominal voltage. This allows for extended voltage drop along the extent of its distribution system to customers. A typical voltage diagram of an EDTI distribution circuit is shown below:

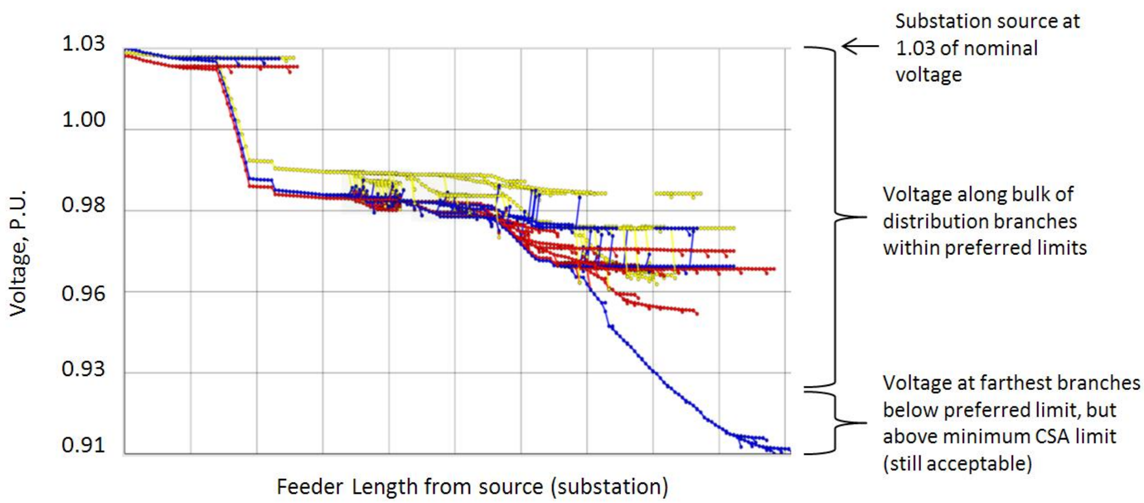

Figure 4. Typical Distribution Circuit Voltage Profile at EDTI

To properly assess the voltage results from DER systems at reasonable intervals on EDTI’s distribution circuits, each circuit was subdivided into ‘bus nodes’ or common areas of expected similar behavior due to low impedance. Voltage was then evaluated & analyzed for each ‘bus node’ section, to allow comprehensive analysis of overall circuit behaviors. Typically, between 80-300 bus nodes were identified per circuit, depending on its complexity. An example is shown below:

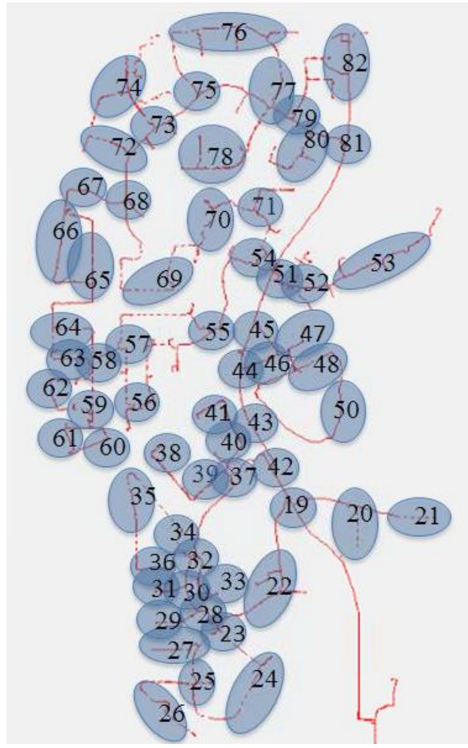

Figure 5. Example Bus Node Breakdown of Distribution Circuit for Result Analysis

The resultant output of the data per each penetration level (10% to 100%) can then be visualized using a box-plot diagram:

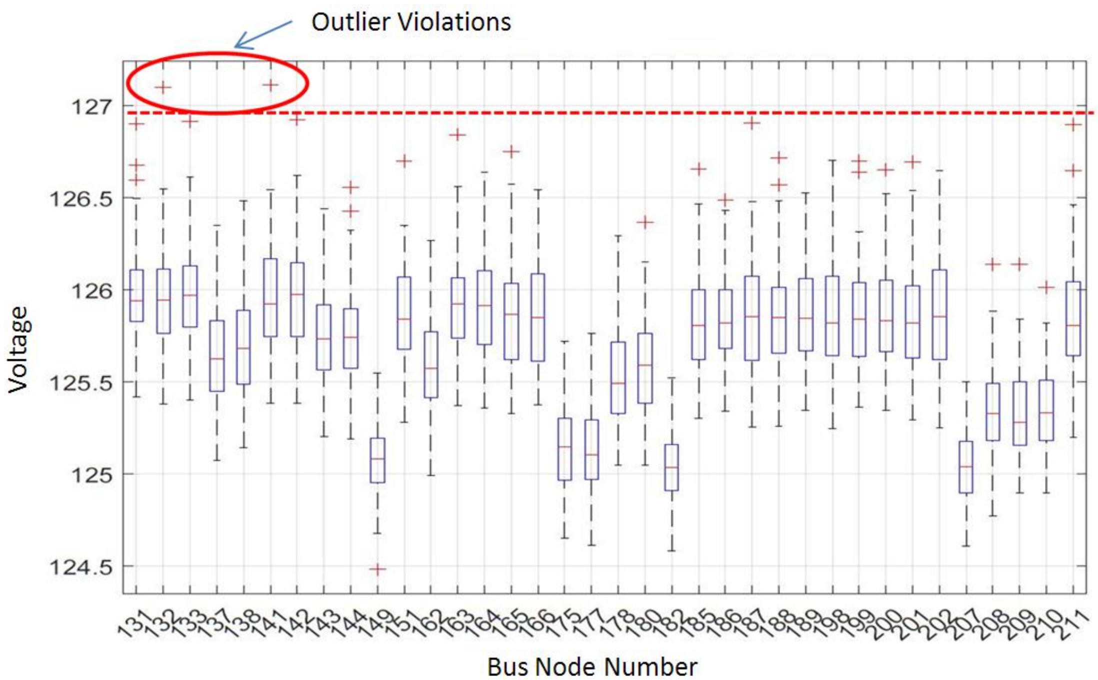

Figure 6. An example box plot of statistical voltage behavior, based on 100 iterations of a single PV penetration level on a circuit, with voltage quality violations occurring as outliers at bus nodes 132 and 141

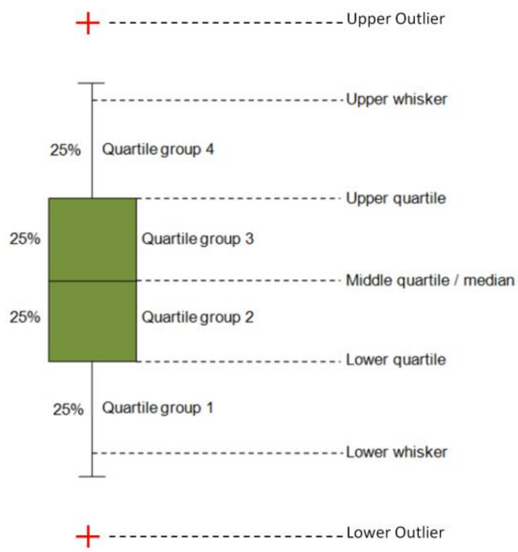

Figure 7. Box Plot Interpretation

In the above example, the box plots of voltages at each bus node represent the statistical distribution of voltage results over 100 iterations with random seeding of a DER technology (in this example, PV systems). This allows the expected *bounds* of behavior, including voltage quality violations, of each section of the circuit to be determined for each level of DER penetration in the distribution system.

Using these statistical results per bus node, the data can also be visualized, per penetration level, geographically:

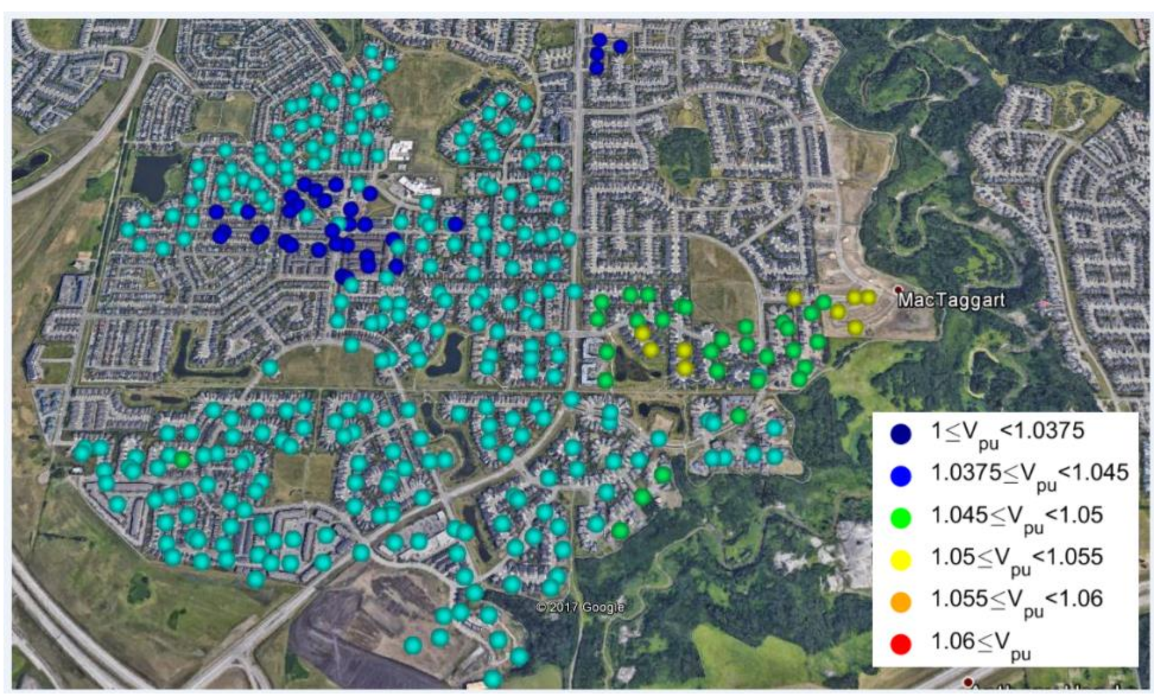

Figure 8. Upper Quartile Voltage Results, per Bus Node, for an Example Circuit with 40% PV Penetration, showing areas with voltages (yellow) reaching ~1.05 per unit

In the above example, the *likely* hotspots for over-voltage are now identified.

Using these methods and analysis techniques, the predicted voltage behaviors of the sample EDTI circuits were determined for 3 case scenarios:

1. PV penetration from 10% to 100% of customers with PV arrays sized to their load;
2. PV+ES penetration from 10% to 100% of customers;
3. EV Charging penetration from 10% to 100% of customers;

A presentation of the key observations, learnings, and risks from the analysis of these scenarios follows.

Discussion and Results

1. PV Systems

The study of the impacts of PV systems was performed under two main assumptions:

- PV penetration level for a distribution system is determined as a percentage of customers on that circuit, with arrays sized to their maximum metered load, that could be served by the totality of installed PV generators.
- However, the overvoltage problems would appear at the times of light load. Thus, based on the analysis of general daily load profiles, the light load has been set for each analyzed circuit individually as approximately 30% of the full load for the circuit.
- In the bulk of the simulations, it is assumed that the inverters cannot control voltage. Therefore, unity power factor (PF) is used, which also corresponds to the worst-case scenario. It is worth mentioning that at the time when the study was initiated, the then active “IEEE 1547-2003 - IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems” [3] made the same assumption. However, the revised 2018 edition of the IEEE 1547 Std now discusses that modern inverters can be considered as a tool for voltage and reactive power control. Nevertheless, the assumption for unity PF simply means that the results of this study are conservative enough.

As already discussed, the analysis was carried out using Monte Carlo simulations and for each PV penetration level 100 iterations were performed while keeping track of and ensuring convergence (see Fig. 9).

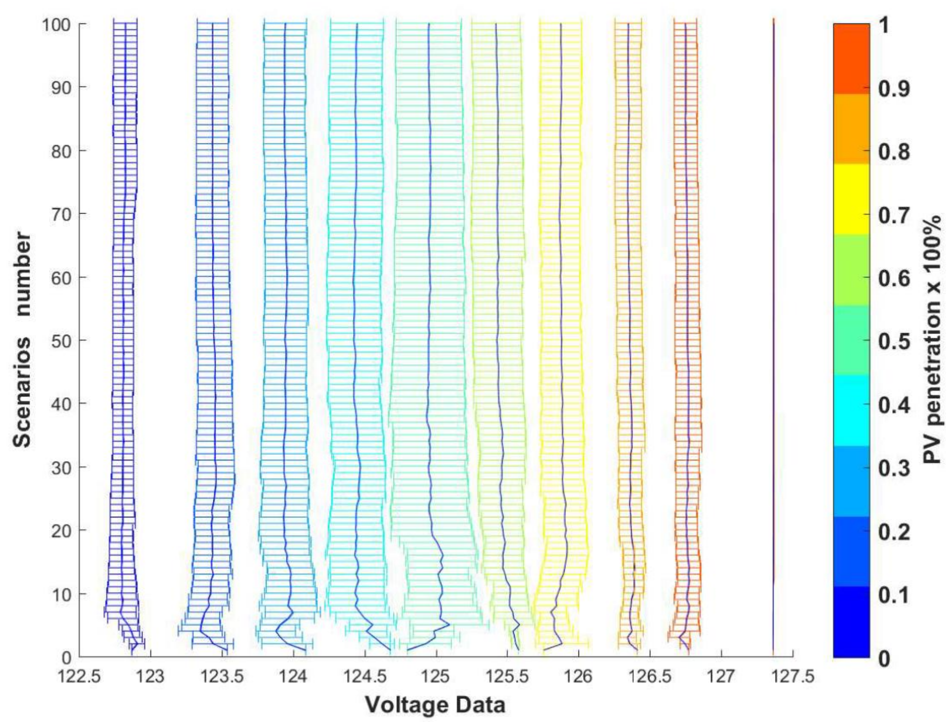

Figure 9: Statistical analysis of one of the analyzed circuits, showing results convergence over 100 iterations

The results are summarized in Fig. 10. They show that if customer PV systems are in-line with minimum loading, about 90% of the EDTI circuits should only experience outlier/local problems.

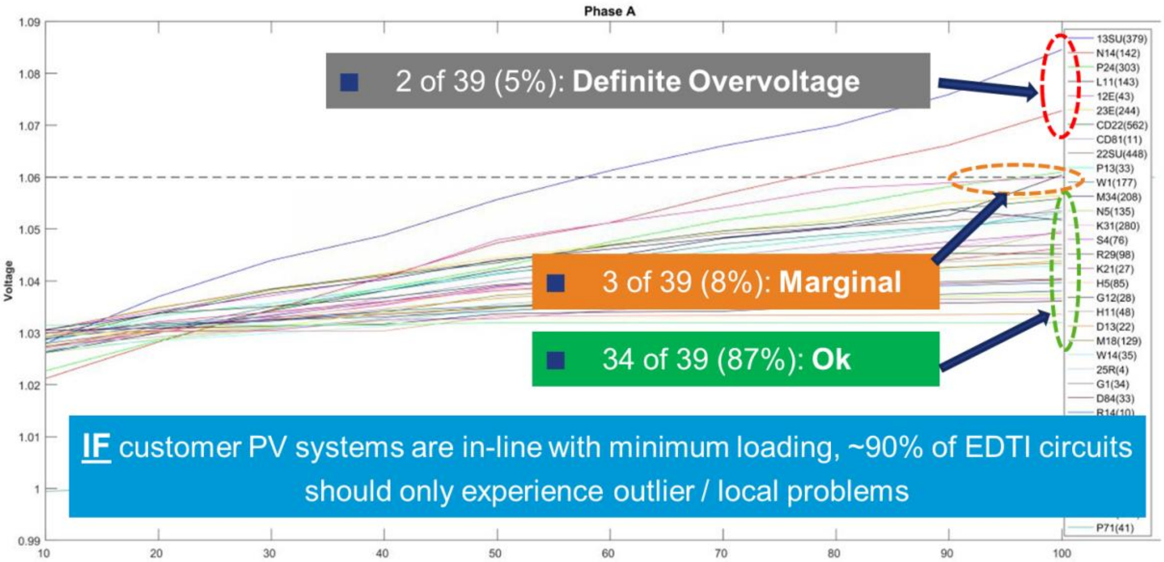

Figure 10: Voltage level vs. PV penetration level

Both circuits for which definite overvoltage was observed at and above 60% PV penetration have similar topologies – they represent large load centers at the ends of long feed lines (see Fig. 11 and 12).

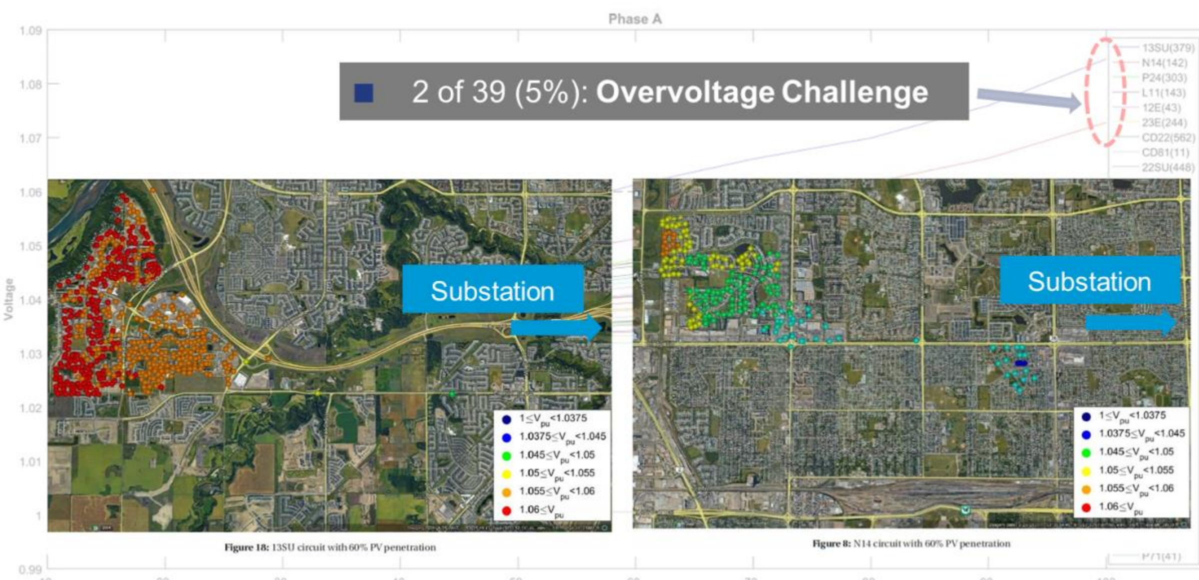

Figure 11: Geographical visualization of the two circuits with worst voltage profile in high PV penetration level "lump-at-end" topology.

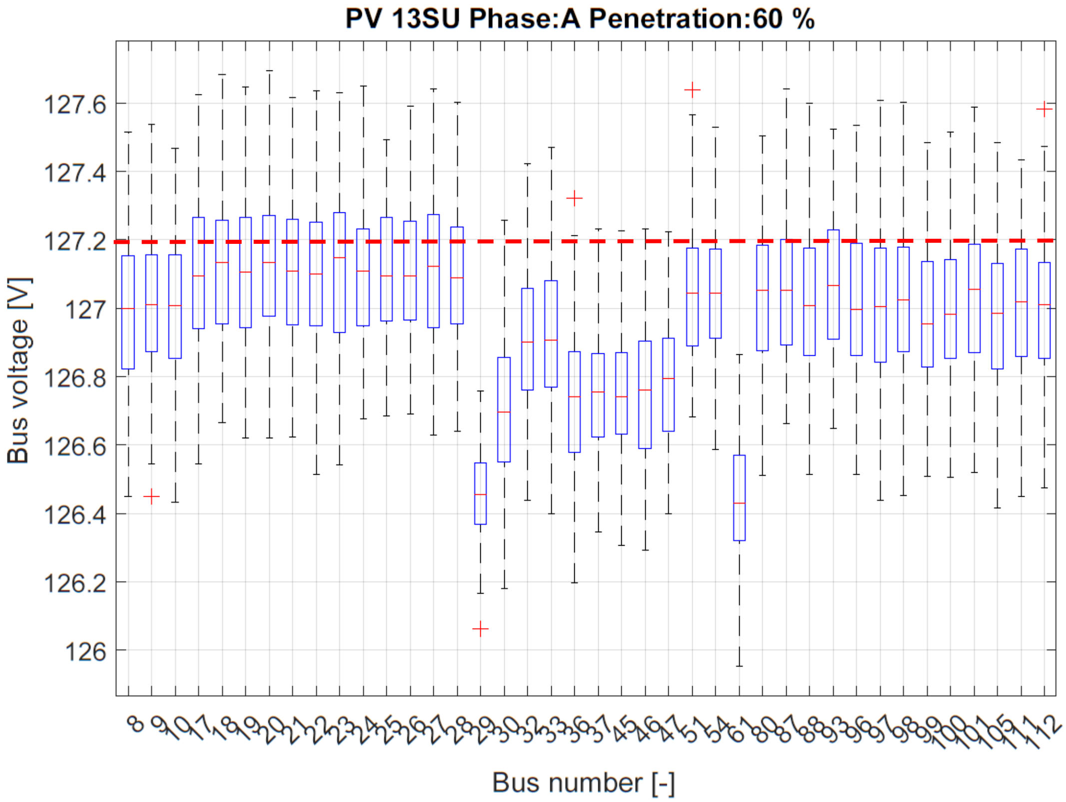

Figure 12: Box plot of phase A of the circuit with the worst voltage profile, for 60% PV penetration

Overall, the issues with PV penetration in EDTI's system can be summarized as follows:

1. Risk of localized overvoltage: all circuits show outlier overvoltages emerging at ~60% penetration. This is the approximate threshold at which EDTI will need to reactively intervene with mitigations.
2. Risk of whole-circuit overvoltage: there are approximately 10 circuits in EDTI's distribution system which fit the description of "lump-at-end" topologies. As the study indicates, these circuits could experience whole-circuit overvoltage affecting the entire trunk of the circuit; for these circuits, local mitigation strategies may not be sufficient.

The research team studied the following possible mitigations:

- Inverter power factor control: this is a method where the customer owned inverter is set to operate at a lower power factor, and absorb VARs for the purpose of reducing voltage. These modes of operation (smart inverters) are starting to become established as part of the IEEE Standard 1547. Unlike the above, this technique was partly simulated as part of the study (see below), to examine the sensitivity of overvoltage reduction to power factor on EDTI's circuits. While promising, this technique does have a significant downside: reducing power factor increases the overall loading of the distribution elements on the circuit (including cables and transformers) and requires either coordinated control system action to monitor / adjust inverter settings or standardization of inverter settings to avoid conflicting operation modes. On average, for EDTI's circuits, 1% p.u. voltage reduction was observed for each 0.1 decrease in power factor.

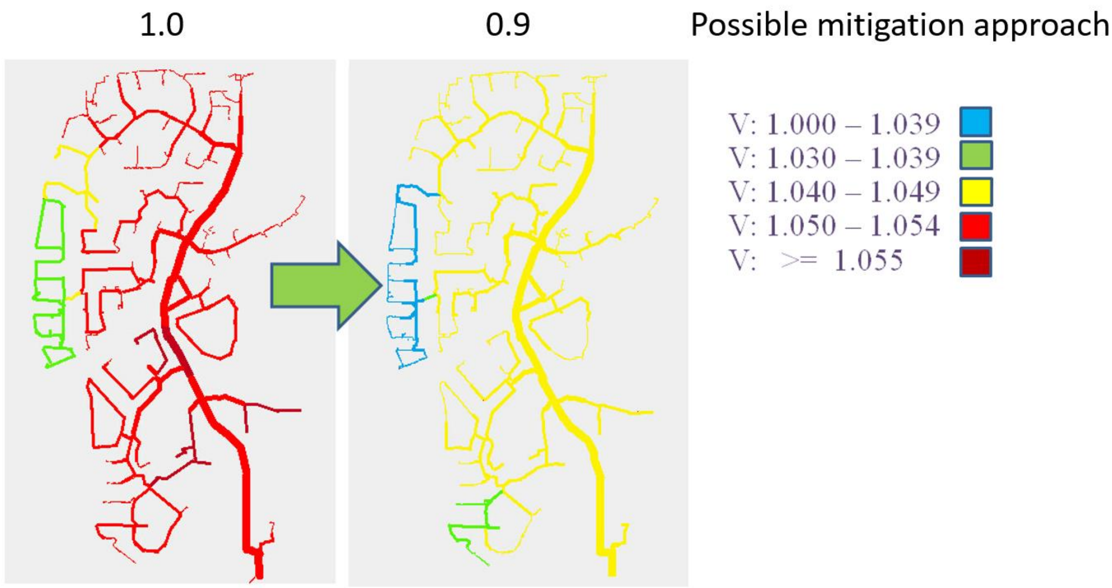

Figure 13: Example overvoltage reduction due to the reduced circuit power factor.

- Adding batteries (or energy storage, ES) locally at the customer site to offset PV generation – this is the subject of the entire second section of this report.

Other possible mitigations identified (but not studied in detail) include:

- Local voltage regulating appliances: these are typically ±10% voltage controlling power electronic regulating devices designed to be installed on the secondary side of distribution transformers. These can be used to reactively address local areas of the distribution system where one or multiple DG sites are injecting power back into the distribution system. The power electronic nature of the regulator makes it suitable for the high degree of temporal variability characteristic for PV systems.
- Circuit re-configuration or "design-by-policy" can be used to correct or avoid "lump-at-end" topologies which are at risk of whole-circuit overvoltages.
- CVR or Volt-Var optimization: is a central automated control strategy designed to minimize the voltage profile on a distribution circuit, typically implemented to reduce energy consumption for resistive loads. While this technique does requires the installation of power conditioning equipment (e.g. regulators) in the distribution circuit, it does offers a system-wide methodology to increase available "headroom" for voltage rise due to power injection. In addition, smart inverters may also offer a mechanism for achieving volt-var control on a system-wide basis, but would require system-wide coordinated control.

Because the study results indicate EDTI can tolerate a relatively high amount of PV or DG penetration on a distribution power system, another generalized risk associated with residential PV systems also becomes significant - the "hidden load" concept. When a significant amount of PV is present, its generation is being absorbed by the load on the circuit, and the remaining load is fed by the main distribution circuit. Therefore, without real-time signals on each inverter, the utility does not actually know the "true" amount of load on the circuit.

Then, if a section of circuit is de-energized, the PV inverters self-isolate, as they require a grid-supplied 60Hz reference to operate. Once they have disconnected, they require grid frequency for certain amount of time (typically 30-60 sec) to reconnect.

The problem with this behavior is that distribution systems always have planned or unplanned outages to whole circuits or portions of circuits. In a high PV penetration scenario, this means that a greater portion of the actual real load is being offset by the PV generation, and it is extremely difficult to estimate what the load will be after a restoration, when the generation is absent for 30-60 sec. In the worst case this could lead to overloads, unwanted protection trips, and significantly complicate restorations.

From a planning perspective this means that one cannot use aggregate SCADA data for planning purposes, if a significant portion of the peak is being offset by distributed PV. So, this issue poses a problem from both the real-time operations and planning perspectives.

Unfortunately, this problem is not-trivial to solve. Some potential solutions include:

1. Adding SCADA to all PV sites (not economically practical);
2. Metering PV separately from the residential load (solves the planning problem, but not the real-time problem);
3. Implement a Distributed Energy Management System (DERMS) to estimate the real-time "hidden-load" system wide. This is still only an estimation, but it might be the practical solution to address both real-time and planning needs.

2. PV + Energy Storage

In the second phase of the study, customer owned energy storage was added to the mix and all simulations were repeated. In the context of the performed analysis, ES was studied in terms of its applicability to buffer and smooth the outputs of PV systems as a possible mitigation technique for excessive PV generation.

In this respect, it was observed, that ES systems can cause severe overvoltage issues when the ES devices are operated in discharging mode. Conversely, charging of ES devices can lead to unacceptable undervoltages. An example is demonstrated in the figure below, for the same circuit with ES systems operating in different modes:

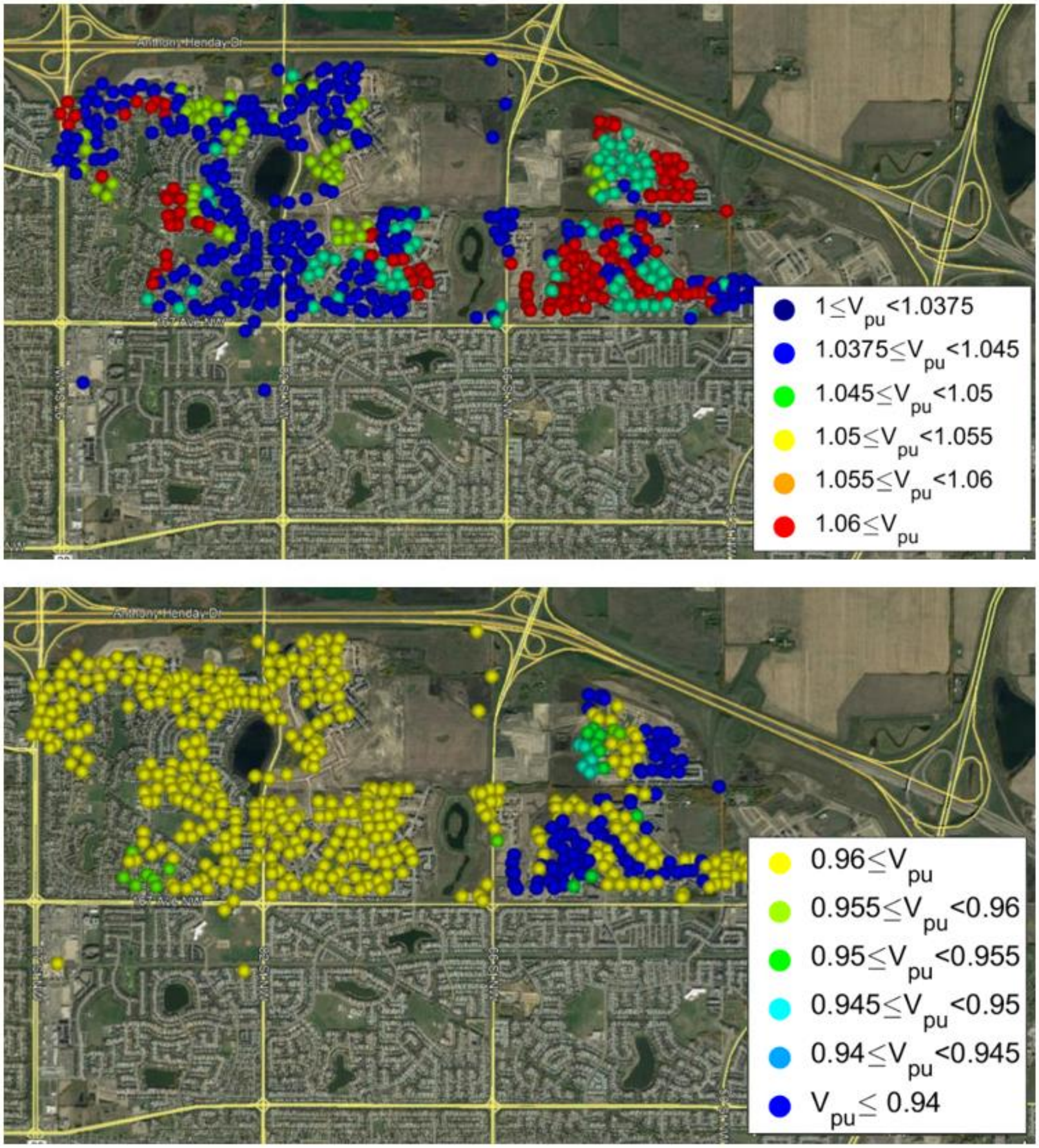

Figure 14: Same circuit, 40% PV+ES penetration, top figure: ES systems discharging, bottom figure: ES systems Charging.

The instances in the above figures can be considered to occur at two different times in the same day. This was modelled in the study by considering the effect of different control strategies for the ES systems.

When no special control strategy is utilized and flat-rate PV self-consumption strategy is used, at certain penetration levels (as low as 30 %), charging of ES devices even causes system overloading issues. It was also found that the impact of ES systems depends mainly on the penetration level of ES devices for systems with most industrial customers and depends on both the locations and penetration levels of ES devices for systems with many commercial and/or residential customers.

However, it is worth noticing that unlike PV, ES systems are fully controllable, and the study demonstrated that different energy storage management strategies (application of time-of-use, TOU, energy rates as opposed to flat rates) can have significant effect on the network congestion (overloading) and the overall ES impacts on the network:

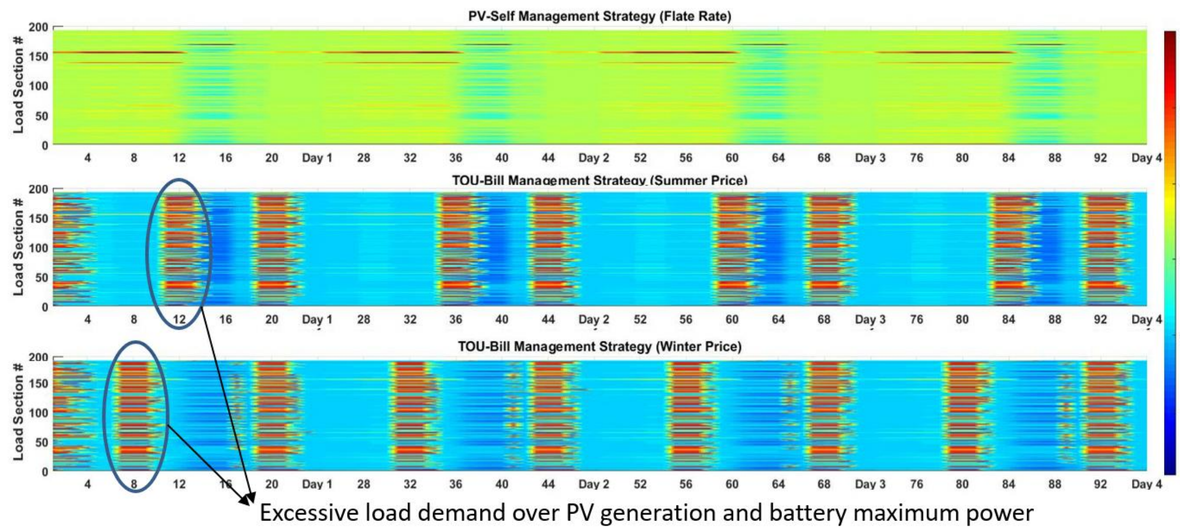

Figure 15. The net power of each sections in a given circuit, for different energy management algorithms

As demonstrated above, the TOU strategy can lead to a loss of diversity (or an increased grouping of charging / discharging cycles) in customer owned ES systems. This suggests that for the best outcome as a PV mitigation strategy, the flat-rate self-management strategy should be preferred.

Overall, based on all of the simulations performed in the study, adding ES to PV sites in EDTI's system had the following effects:

- Risk of localized overvoltage: all circuits showed increased outlier overvoltages emergence at ~70% penetration, compared to ~60% without ES. This represents only a modest improvement (over PV only installations) in the penetration level at which EDTI must intervene to maintain power quality.
- Risk of localized / whole-circuit undervoltage: all circuits showed outlier undervoltage occurring at ~60% penetration, the same level at which PV alone showed outlier overvoltage problems.
- The 'swing' from low voltage to high voltage is much larger than PV systems alone, representing an even greater voltage control problem.

Finally, the addition of ES charging / discharging adds to the 'hidden load' problem identified with PV systems:

- ES's desired smoothing of load / PV generation further obfuscates the real load present in the system, making prediction without direct measurement all but impossible;

- Depending on local controller configuration, commercially available ES systems can have a program mode to move to "max charge rate" to recover energy used or not collected during an outage – this is particularly problematic for utilities as during restorations the utility may be restoring all of the real load on the system + every ES system at max charge rate, increasing risks of overload, protection trips, etc.

Based on the analysis presented above, encouraging the addition of ES systems to PV sites is not an effective mitigation strategy for the utility. In fact, it presents a different set of challenges based on the control setup of the local ES system. It is worth noting that this statement correspond to ES systems installed at random locations with uniform distribution. A more systematic ES deployment may provide different results.

3. Electric Vehicles

To estimate the charging profile as well as the impact to the power gird, three issues with EV charging modelling should be considered: start charging time, charging power and charging duration. The 2009 National Household Travel Survey (NHTS) - Daily Trip [4] was used in this research to draw the characteristic of EV charging. The detailed process is shown in Fig. 16.

Two cases of sample ranges are considered. The first one is the overall US trip data, which involves 136141 families, 247154 vehicles and 1167322 trips. In the second case, the Colorado State's data was considered because it has geographical factors similar to Edmonton. In this case, the data consists of 288 families, 555 vehicles and 2637 trips, as shown in Fig. 17.

The charging load is also determined by charging power and total charging demand. Generally, higher charging power can lead to higher peak load, while lower charging power leads to longer peak charging load duration. So, two issues are involved here:

1. Charging power: This parameter can be obtained from the technical specifications of EVs. A survey was made about the most popular EVs available in Canada by 2016, based on the list given by Canadian Auto-mobile Association (CAA), as shown in Table. 3.
2. Total charging demand: This data depends on two factors. The first one is per km electricity consumption, which can be obtained from the technical specifications of EVs. The second one is driving distance, obtained from the statistical data of NHTS dataset [4].

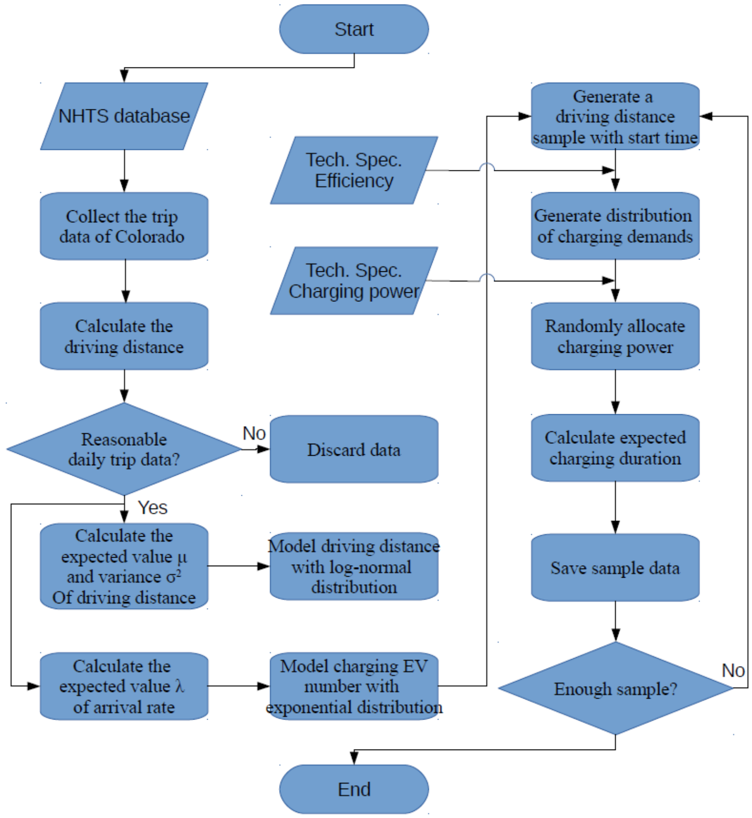

Figure 16. Data mining for charging profile estimation and sample generation

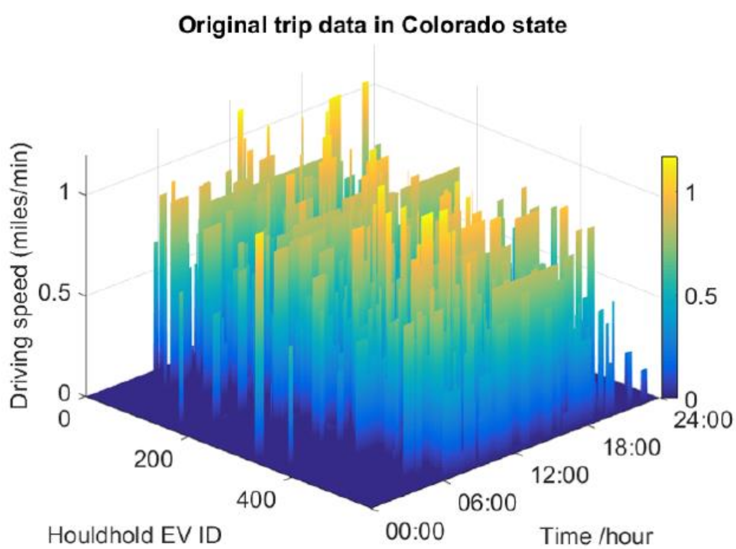

Figure 17. Original trip data in Colorado state

Table 3. Technical specifications of EVs considered in this study

EV Type	*Battery*	*Range*	*Efficiency*	*AC Charging*	*DC Charging*
	kWh	km	kWh/km	kW	kW
Tesla Model S	85	4276	0.2	10/20	50
Ford	33.5	185	0.181	6.6	50
NISSAN LEAF SV	30	172	0.174	6.6	50
BMW i3 (90Ah)	27.7	200	0.136	2.4/7.4/11	50
Kia soul ev	27	149	0.181	6.6	50
NISSAN LEAF S	24	133	0.18	6.6	50
Chevrolet	27	131	0.16	48	50
BMW i3 (60Ah)	18.8	138	0.136	2.4/7.4/11	50
Mitsubishi	16	95	0.168	6.6	50

EV with a daily commuting distance of 40 km requires 6-8 kWh of energy to recharge, which is an equivalent of daily power consumption of a small household. In short, mass adoption of EVs can be clearly identified as a serious challenge for the distribution grid due to the peak load overlapping resulting in significant load increase. Fig. 18 is an example of mixed commercial and residential load. It is to be expected that in such case there would be some mid-day load bump with business trickle-chargers, but when everyone goes back at home at 4-6 pm, then the biggest problem occurs.

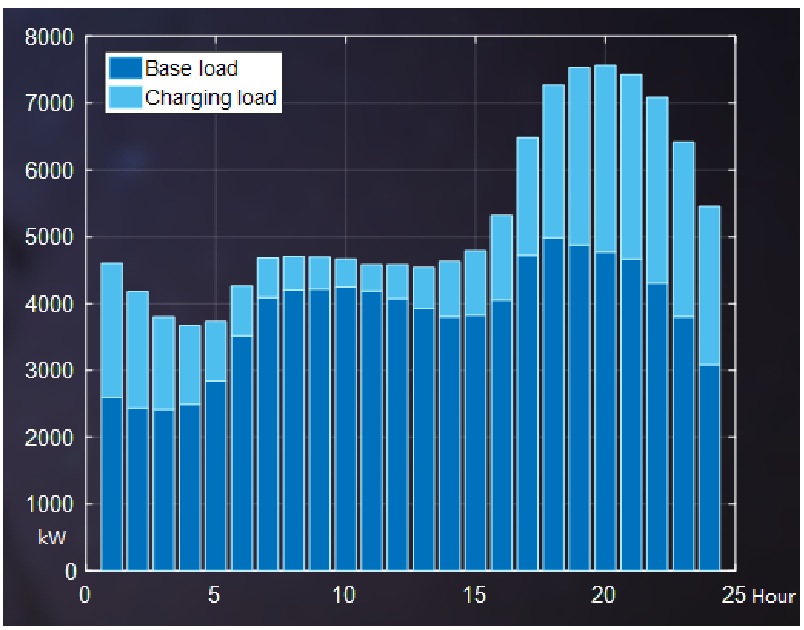

Figure 18. Example of peak load overlapping at the circuit level, showing peak load increase from 5MW to 8MW due to the addition of 100-300 EVs at typical level 2 charging levels.

Typical utility infrastructure does not have a lot of load margin. At EDTI, the margin on distribution feeder capacity is, on average, 33 %. Load does grow, but historically it grows as a small percentage of the existing load. Any large step changes are typically loads in new areas, and infrastructure is designed around them accordingly (new circuits, new transformers, etc.). The root problem is that EV charging load is a step-change of existing loads that traditionally only grow a few percent, and the step change is (relatively) large: a single Level 2 charger at a house can be 20-30 A at 240 V (4.8 kW-7.2 kW), and up to 80A@240V (19kW). In contrast, a typical residential household in EDTI's system consumes 2.5kW-3kW average at peak loading times in the 24-hour loading cycle. This is a game-changing behaviour in pre-existing consumer loading.

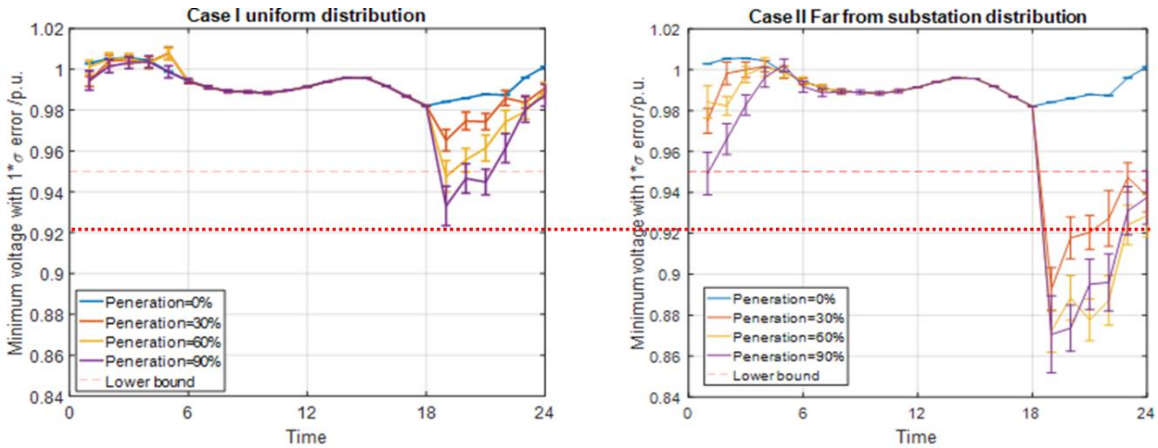

Figure 19. Effects of EV load distribution on overvoltage due to charging

With uniform distribution throughout customers, under-voltage and capacity issues at feeder level emerge around 50% penetration (see Fig. 19). However, if distinct clusters are formed, then this would quickly degrade voltage quality. Thus, it can be said that EVs effects can be highly localized.

In addition, residential transformers represent a significant network bottleneck and are of risk to be easily overloaded. Typically, in EDTI's network, residential distribution transformers are 37 kVA in size (which corresponds to 154 A at 240 V) and serve 12 lots. Although in general, to a certain extent, transformers can be overloaded for short periods (however this affects their lifetime), this is not feasible with the case of EV charging because typical EV charge takes from 2 to 8 hours.

Overall, the issues with EV penetration in EDTI's system can be summarized as follows:

1. Trunk Voltage Collapse: all studied circuits collapse below minimum acceptable voltage when penetration (clustered) increases past 15%.
2. Local infrastructure overloads: all residential transformers 37kVA (~20,000 units in EDTI's system) are at risk. 1-2 typical EV's (7.2kW charging level) representing 2 vehicles per 12 lots (again, 15%) could be enough to overload the distribution transformer with typical residential loading.
3. Feeder capacities: EDTI plans upgrades to circuit infrastructure based on historical assumptions of load density, historical load growth rates, and known upcoming additions (new neighborhoods, etc.). EV charging representing an insertion of relatively random high loads is not something that is currently

planned for. EDTI (and other urban utilities anticipating EV uptake) may have to adjust their long-term planning strategies, which could lead to higher up-front infrastructure capacities.

In addition, there is currently no regulatory or legal mechanism to obligate customers with EVs to notify the utility; this means that without a power quality complaint (or other means of detection) utilities may be blind to where power quality and local infrastructure problems are to emerge.

Possible mitigations identified (but not studied in detail):

1. Demand response (or direct charging control or limiting): time shifting charging to off-peak, or reducing charge level available at residential sites could be used to 'spread' the energy demand of EVs and reduce capacity and voltage impacts; however, in Alberta's current regulatory climate, it is unclear how this could be achieved except through voluntary customer participation;
2. Identifying EV charging through AMI data: data analysis of energy consumption provided by AMI meters may offer a 'passive' method of identifying where EV charging is occurring, allowing the utility to respond to any possible infrastructure impacts (transformer loading, etc.)

Conclusions

The key findings of this extensive study on the impacts of Distributed Energy Resources on EPCOR's distribution network, conducted by a research team from the University of Alberta, can be summarized as follows:

- The main impacts of DER in the distribution grid are in terms of voltage quality (over- and under-voltage) and infrastructure capacity (power lines and transformers overloading). Effects on protection, fault levels, and fusing were investigated, but yielded no significant effects, and are therefore omitted from this paper for brevity.

- EDTI's grid is well-positioned for PV uptake, if customers stick to 'appropriately' sized arrays (and exceptions can be easily identified based on topology).

- The near-term and most significant challenge is in-house EV charging. Even for relatively small penetration levels, due to the peak load overlapping, they represent potentially significant loading impact to local infrastructure (especially if clustered in certain areas).

- Although customer ES represent similar issues like PV when discharging and like EV when charging, they have much more flexibility in terms of control and can be treated as a longer-term challenge.

- There is a need for further analysis and pilot projects in order to assess non-wire alternative measures (which make use of advanced control schemes, power electronics, communication, and control) and/or regulatory changes (e.g. dynamic pricing, increase allowance for capacity, demand-response, EV charging limiting / control).

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