



# Distribution Grid Impact Study in Highland Park, Michigan

**Understanding Rooftop Solar, Behind-the-Meter Energy Storage, Electric Vehicle Charging, and Building Electrification**

Erik Pohl, Kapil Duwadi, Tucker Oddleifson, Shibani Gosh, Vignesh Ramasamy, Patrick Gibbs

National Renewable Energy Laboratory

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# Notice

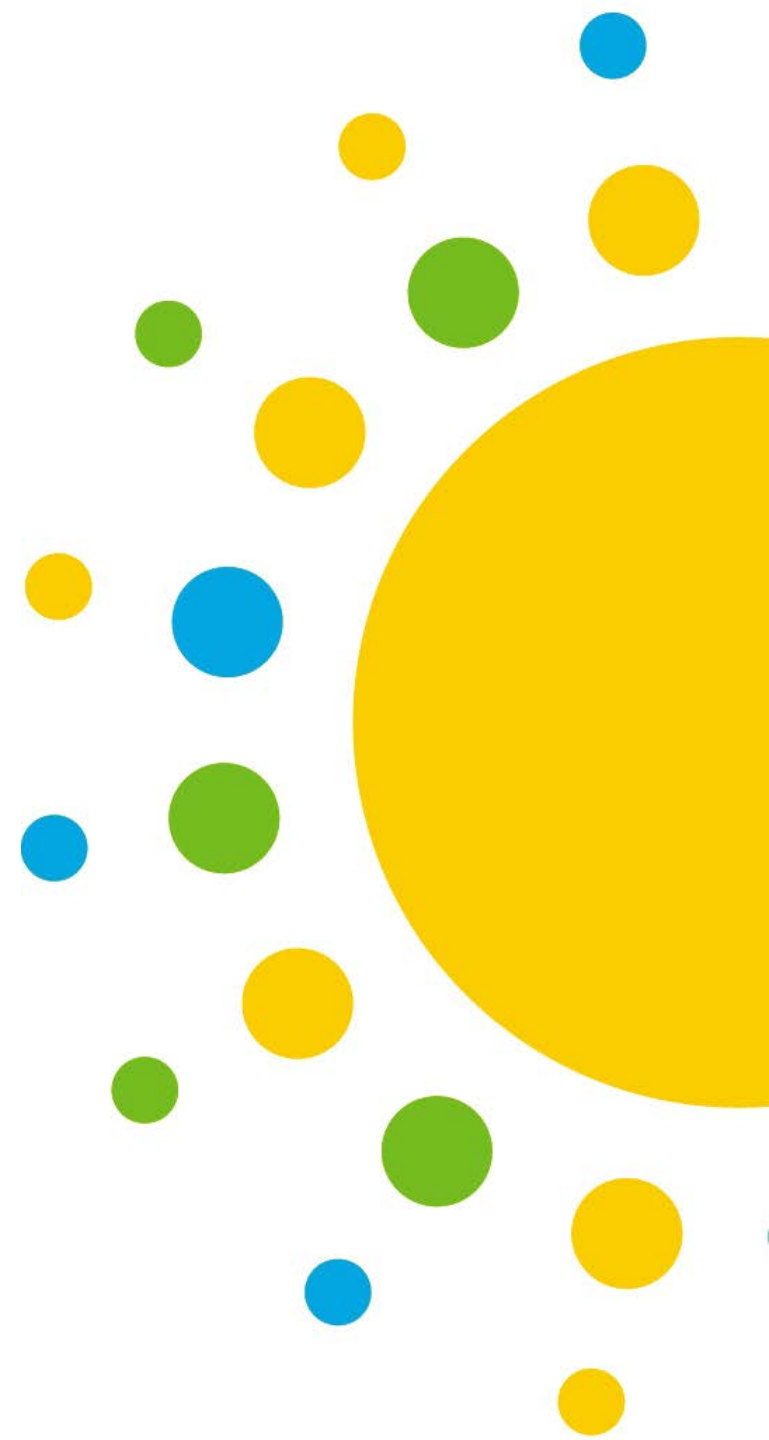
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*National Renewable Energy Laboratory  
15013 Denver West Parkway  
Golden, CO 80401  
303-275-3000 • [www.nrel.gov](http://www.nrel.gov)*



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# Terminology

- **Current Model:** Distribution circuit load flow model reflecting the current design, construction, and voltage class (4.8 kV).
- **DER:** Distributed energy resource, defined by the Federal Energy Regulatory Commission (FERC) as follows: “DERs are small-scale power generation or storage technologies (typically from 1 kW to 10,000 kW) that can provide an alternative to or an enhancement of the traditional electric power system. These can be located on an electric utility’s distribution system, a subsystem of the utility’s distribution system or behind a customer meter. They may include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment.”<sup>1</sup>
- **Primary Line:** Medium voltage overhead wire or underground cable.
- **SARDI:** System average risk duration index measuring the sum of customers hours impacted by voltage and thermal violations and normalized by total customer hours (expressed as a percentage).
- **Secondary Line:** Low-voltage overhead wire or underground cable. Secondary Lines may be connected directly to the low-voltage side of the service transformer or may be connected to other secondary lines in a network and may serve one or more customers.
- **Service Drop:** Low-voltage overhead wire or underground cable, directly connected to a customer’s house. A service drop generally serves only one customer.
- **Transformer:** A power systems device to convert, in our models, medium voltage (e.g., 4.8 or 13.2 kV) down to low voltage (e.g., 120/240V). This represents the transition point from the primary distribution network to the secondary distribution network. A transformer may serve one or many individual customers.
- **Upgraded Model:** Distribution circuit load flow model reflecting the likely future design, construction and voltage class (13.2 kV), per the recommendations of DTE engineers.

<sup>1</sup> “FERC Order No. 2222: Fact Sheet.” 2020. Federal Energy Regulatory Commission. September 17, 2020. <https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet>.

# Project Overview

# Communities LEAP Scoping Context

Through the Communities LEAP (Local Energy Action Program) Pilot, the National Renewable Energy Laboratory (NREL) engaged the Highland Park Stakeholder Coalition to scope four technical assistance work areas to address their energy needs and goals.

This slide deck addresses the highlighted tasks under work area “B.”

A . City-Wide Solar Street Lighting and Policy Analysis	B. Grid Analysis	C. Community Choice: Home Energy Improvements	D. Bonus Bucket! Transportation and Mobility with MCC
<ul style="list-style-type: none"><li>• Task 1: Solar Street Lighting Financial Model Review</li><li>• Task 2: Due Diligence References</li><li>• Task 3: Implemented Case Studies</li><li>• Task 4: Master Plan Gap Analysis</li><li>• Task 5: Zoning Code + Applications Gap Analysis</li><li>• Task 6: Review Proposed Solar Ordinance</li></ul>	<ul style="list-style-type: none"><li>• Task 1: Determine Existing Load Profile + Feeder Model (reference case)</li><li>• Task 2: Grid Analysis (limitations and capacity under three growth scenarios)</li><li>• Task 3: Feasibility Analysis 3 Actionable Behind Meter Projects (within City’s authority under current grid configuration)</li></ul>	<ul style="list-style-type: none"><li>• Task 1: Support a coalition-facilitated selection process</li><li>• Task 2: Housing Characteristics and Energy Burden Analysis</li></ul>	<ul style="list-style-type: none"><li>• Task 1: Coordinate with Michigan Clean Cities on feasibility study for Perimeter Loop micro-mobility utilizing EV shuttles</li></ul>

# Project Context

Highland Park, Michigan, community members face frequent, long-duration power interruptions due largely to the aging distribution system serving the area and the legacy design standards used in its construction.

While degrading physical infrastructure such as poles, crossarms, and transformers can result in this substandard reliability, another notable characteristic of this legacy system is the lower, 4.8 kV, voltage class. This is a legacy construction standard which many utilities, DTE Energy included, are phasing out in favor of higher, 15 or 25 kV, voltage classes instead.<sup>1</sup> The existing 4.8 kV distribution system serving Highland Park may limit significant adoptions of clean-energy technologies like high percentages of building electrification or electric vehicle (EV) adoption.

The following analysis seeks to quantify these limitations under a variety of clean-energy technology adoption scenarios. It compares the overall system risks of the present system to those of a hypothetical, upgraded 13.2 kV system, using NREL-developed risk metrics and offers upgrade cost considerations.

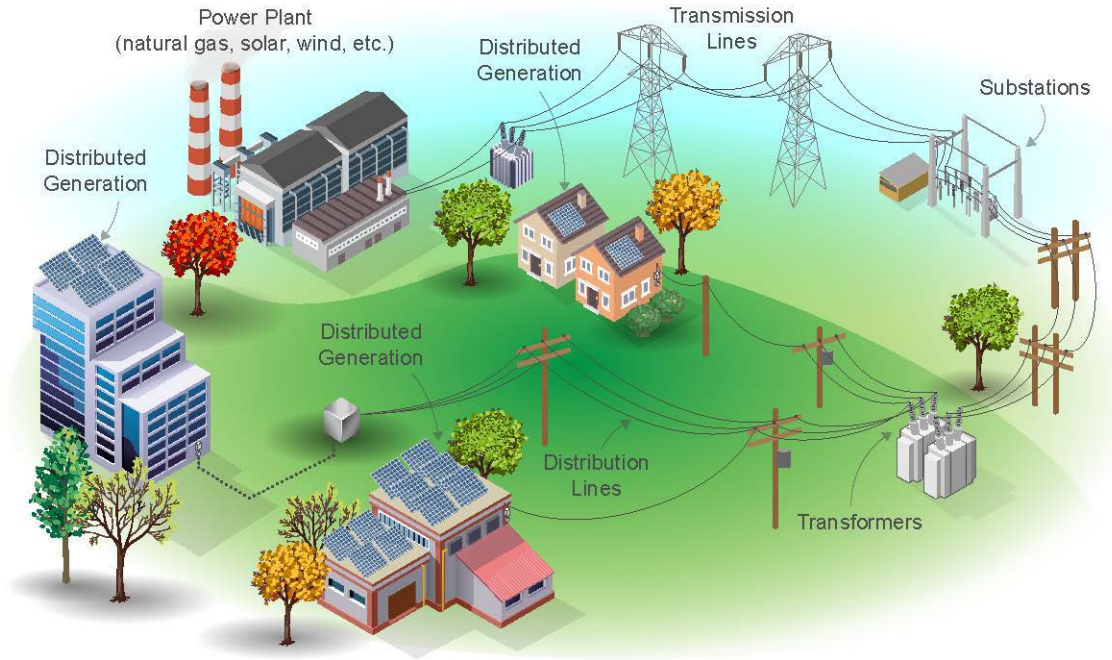
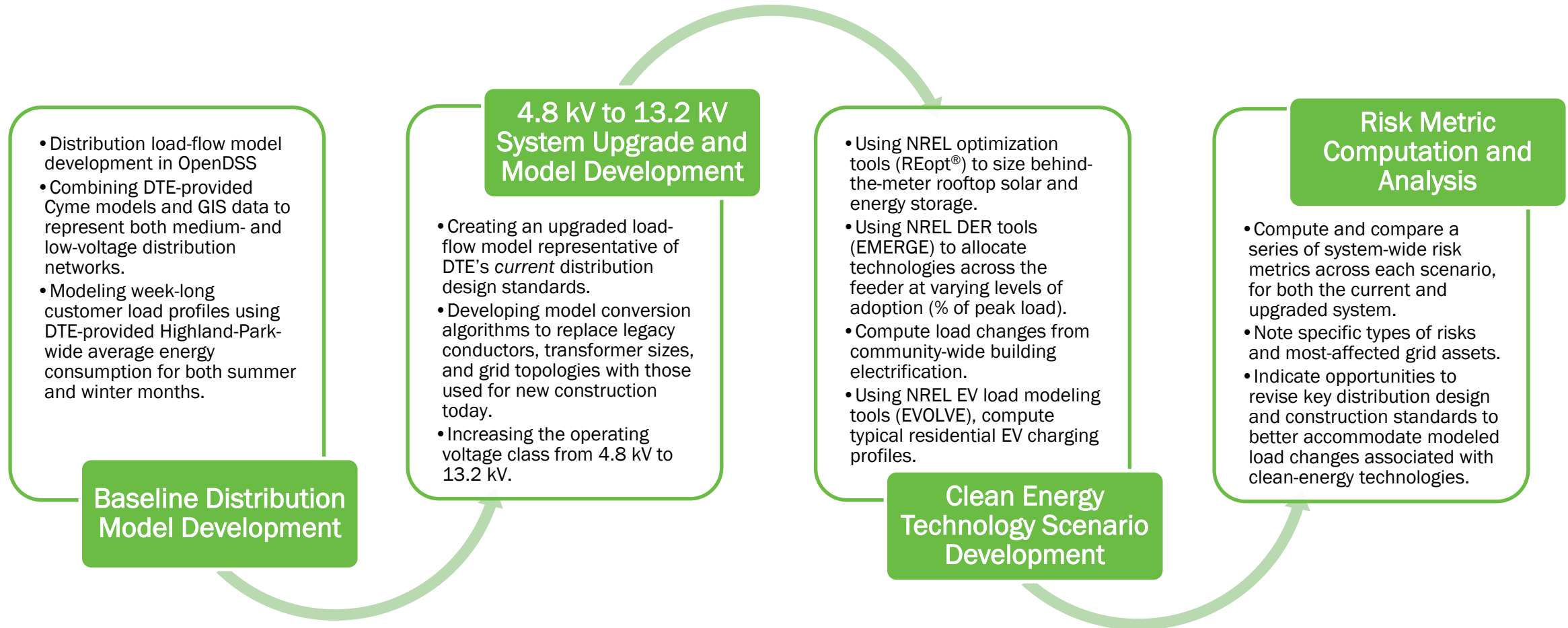


Illustration of the “grid” from utility power plant, transmission, distribution, to distributed energy resources. Illustration by Alfred Hicks, NREL 65851

<sup>1</sup> Wang, Joy. “DTE Electric 4.8kV Technical Conference.” n.d. <https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference>.

# Project Approach: Understanding the Analysis

Using data provided by DTE, NREL modeled a typical distribution feeder in one of Highland Park's mixed-use areas. This model was used to baseline and characterize typical vulnerabilities of the existing distribution grid and assess how it would perform under various load growth and distributed energy resource (DER) adoption scenarios. The results of this study compare the risks of the existing 4.8 kV grid to an upgraded 13.2 kV grid under changing loads due to electrification, EV charging adoption, and DER adoption.



# Key Takeaways

- **The System Today (Current Model):**
  - The legacy 4.8 kV voltage class serving Highland Park is not, as we have modeled it, a major limitation to the widespread adoption of cost-optimal\* rooftop solar and/or behind-the-meter energy storage. Within our modeling framework, these technologies namely impact secondary, low-voltage assets, which may be remedied without the need for a system-wide upgrade to a 13.2 kV voltage class.
  - Our model of the current 4.8 kV system indicates it is not capable of supporting community-wide electrification efforts. Widespread building electrification, and the resulting large increase in wintertime load, dramatically increases the prevalence of voltage violations and thermal overloading on the current 4.8 kV distribution system. These impacts illustrate the need for system-wide upgrades to a 13.2 kV voltage class to accommodate these technologies.
  - Low to Moderate DER adoption does not adversely impact the grid but does improve undervoltage and asset overloading issues. However, these benefits are insufficient to defer grid upgrades. Higher DER penetration is shown to increase overvoltage and asset overloading in future electrification scenarios.
- **The System of Tomorrow (Upgraded Model):**
  - In all cases, upgrading the system to a higher voltage class and using modern design standards significantly reduces system risks associated with the adoption of DERs or building electrification.
  - The persistent violations remaining on the upgraded system are largely concentrated in the low-voltage secondary networks and service transformers. This illustrates the need for more robust secondary design standards to accommodate the large increases in load. Such standards may include larger secondaries, service drops, and transformers, or serving fewer customers per transformer.
  - Further study is required to estimate the cost of system-wide upgrade needs specific to Highland Park. See slide 69 for cost considerations.

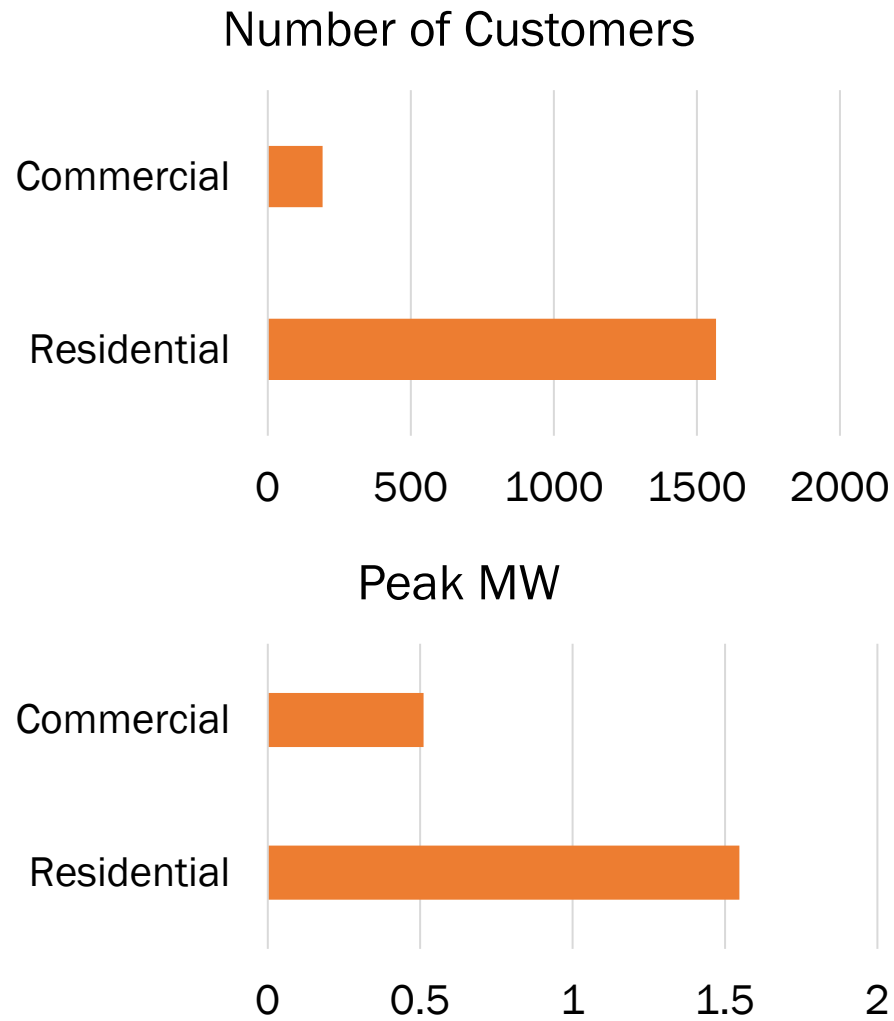
*\*Cost-optimal refers to the size of rooftop solar and/or energy storage systems which minimizes the financial burden on participating community members. This optimization was performed using NREL's REopt tool and is detailed in the accompanying slide deck.<sup>1</sup>*

<sup>1</sup> Oddleifson, Tucker, Kapil Duwadi, Erik Pohl, Patrick Gibbs, Shibani Ghosh, Chrissy Scarpitti, and Liz Weber. 2024. "Prefeasibility Analysis of Behind-the-Meter Distributed Energy Resources in Highland Park, MI." February. <https://www.nrel.gov/docs/fy24osti/87988.pdf>.

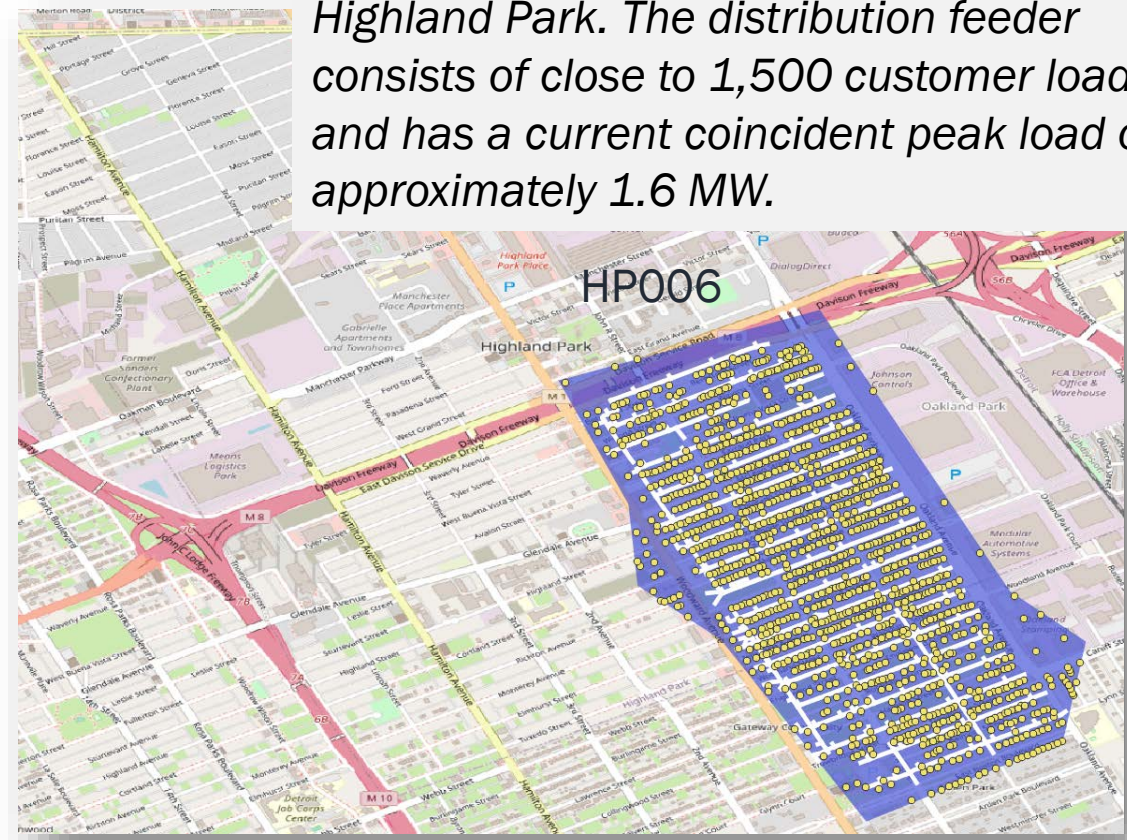
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# Methods of Analysis

# Understanding the Grid As It Is – Location and Customer Class



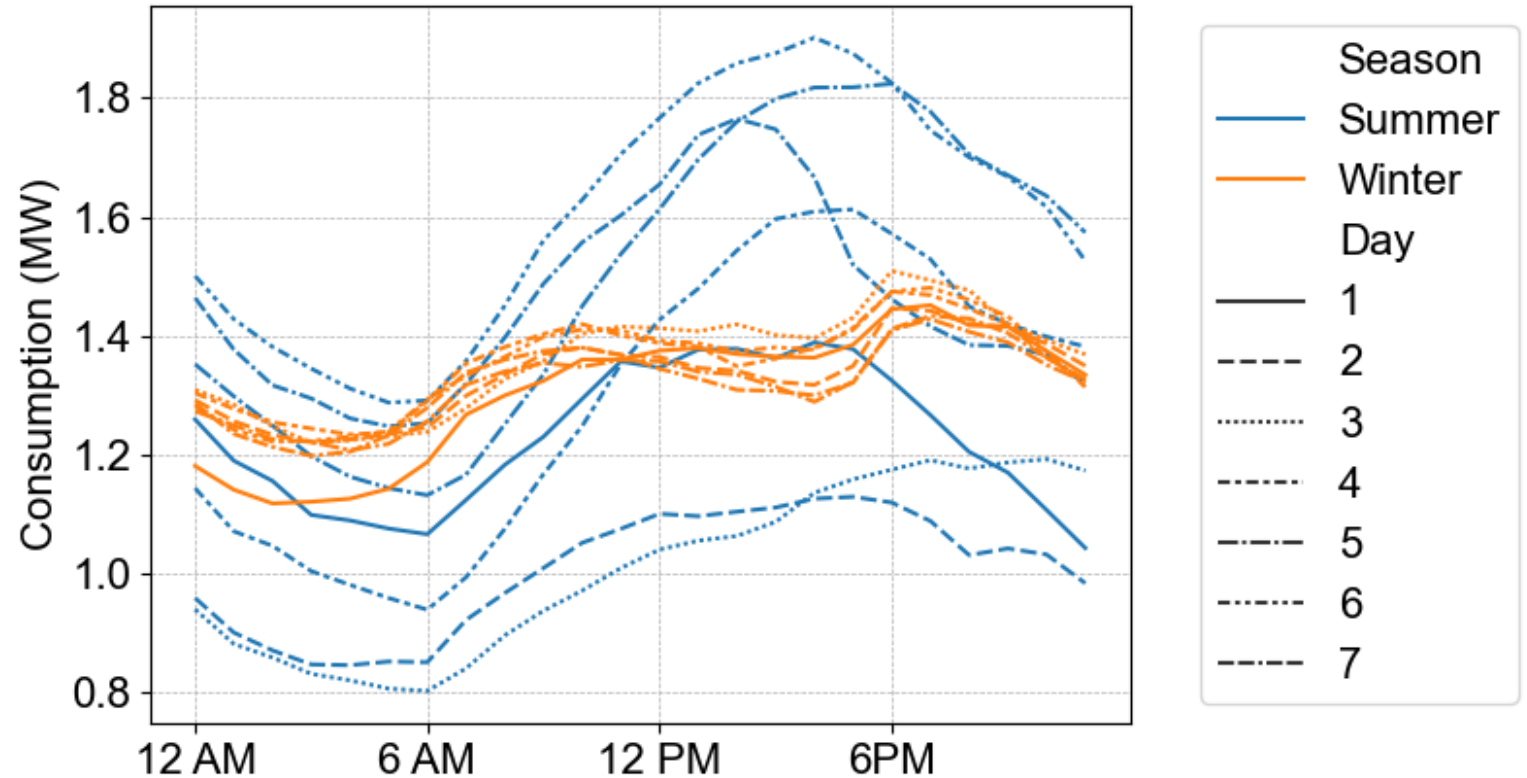
For this study, we looked at a mixed-use feeder (though majority residential) within Highland Park. The distribution feeder consists of close to 1,500 customer loads and has a current coincident peak load of approximately 1.6 MW.



Model includes only a portion of Highland Park

# Understanding the Grid As It Is – Seasonal Load Profiles

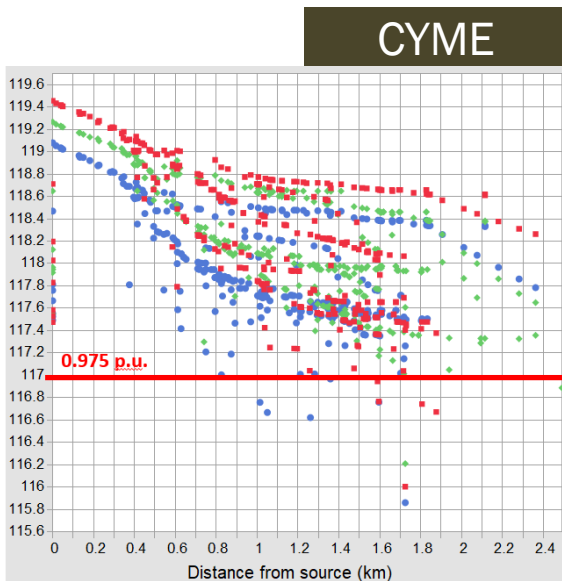
We used average timeseries load consumption data (also known as load profiles) for residential and commercial customer groups provided by [DTE Energy](#) as an input to our timeseries power flow analysis. To understand the grid impacts under the various scenarios described in later slides, we looked at weeklong simulation results for a summer and winter peak consumption week. The resulting load profiles, shown here, illustrate that during our summer week, the system generally sees peak load in the afternoon to early evening, while winter days more consistently peaked around 6 to 7 p.m.



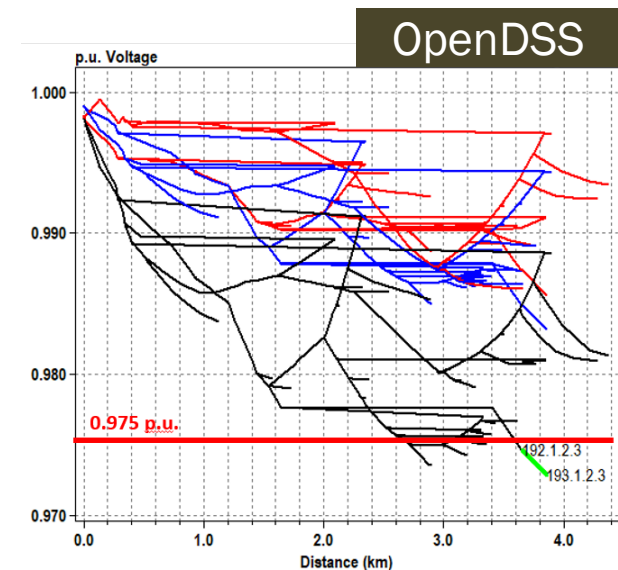
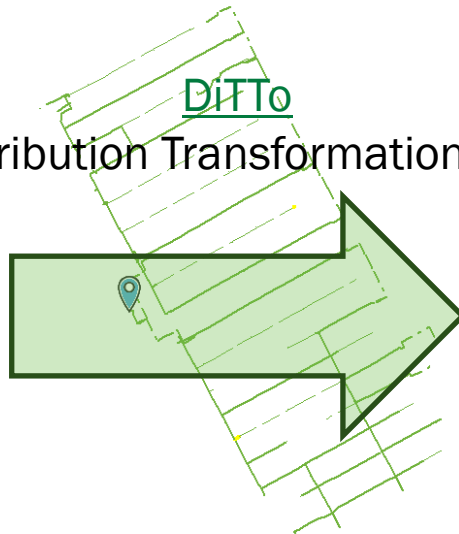
**\*Summer Week: July 1–July 7, Winter Week: Feb. 5–Feb. 11**

# Understanding the Grid As It Is – Distribution System Model

The first step of our analysis was to convert the DTE-provided load flow model of a Highland Park feeder to a format compatible with NREL's analysis tools. The model was provided in the format used by [Eaton's CYME](#) distribution modeling software. Using an NREL-developed software called DiTTo (Distribution Transformation Tool), we converted this model to be analyzed in the open-source tool, [OpenDSS](#), developed by the Electric Power Research Institute (EPRI). The provided CYME model also contained only information of the medium-voltage distribution network, with no depiction of the low-voltage secondary networks, serving individual customers. As such, we leveraged DTE-provided GIS data depicting the topology of these networks and [Microsoft's open source parcel](#) data to add these missing components to the feeder model.



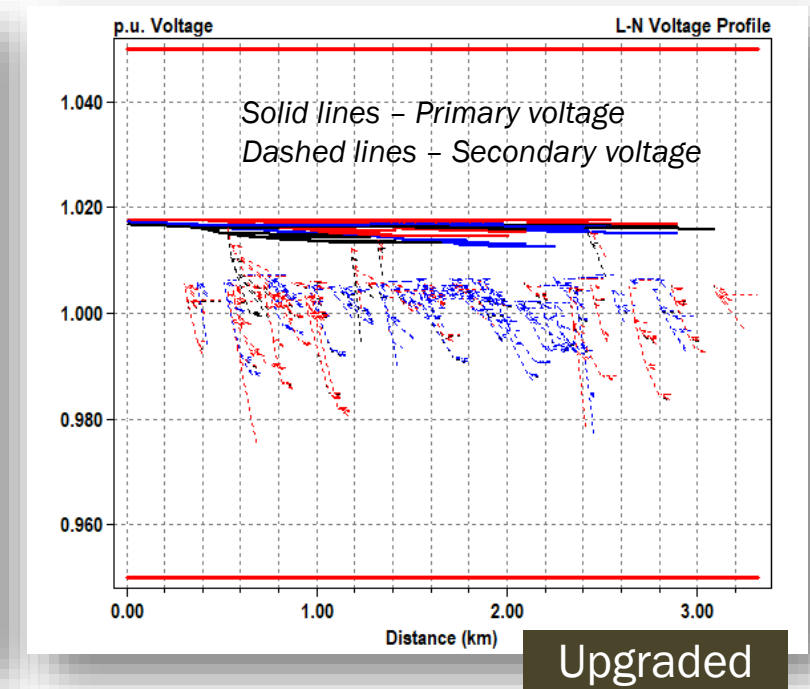
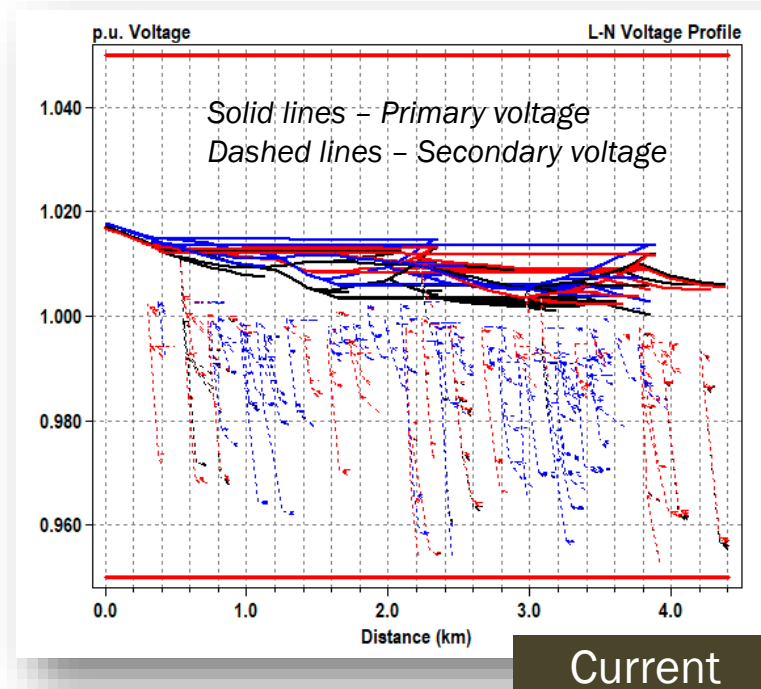
**DiTTo**  
(Distribution Transformation Tool)



# Upgrading the Grid – Current and Upgraded Models

	Primary Backbone	Secondary Main	Service Drop	Transformers
Current Model	OH (4/0 Cu, #2 Cu, #4 Cu, #6 Cu) UG (4/0 Cu, 450 kcmil Cu)	Open-wire 1/0 ACSR, Open-wire 4/0 ACSR	#2 AL Triplex	Original sizes
Upgraded Model	OH (636 Al, 1/0 ACSR) UG (1000 kcmil AL, #2 AL)	1/0 AL Triplex, 4/0 AL Triplex	#2 AL Triplex	<50 kVA TO 50 kVA (31/112 Transformers Replaced)

The table above lists the distribution assets that were replaced in our upgrade process. Another key characteristic of the Current Model was the presence of looped primary circuits (i.e., parallel paths from the source to loads, without any breakpoints). This is also a legacy design practice and was remedied in our Upgraded Model, by installing normally-open switches where loops exist, creating a truly radial distribution feeder topology.



# Understanding DER Impact: Scenarios

In all scenarios, the size of rooftop solar and energy storage systems are prescribed by NREL's [REopt software](#). The key assumptions used in this tool are explained in detail in the accompanying slide deck.<sup>1</sup>

NREL's [EMERGE](#) software is used to perform timeseries power flow analysis (summer and winter week) at 20%, 40%, 60%, 80% and 100% (% of peak load) adoption scenarios. Future electrification scenarios include electric heating as well as high efficiency appliances, and enclosures.

The table on the right shows all the scenarios and load multipliers used to size the solar and energy storage. For electric vehicles, a fixed charger size was used (1.2 kW for Level 1 and 7.6 kW for Level 2) assuming a mix of 20% Level 2 and 80% Level 1 chargers. The time-series load profiles for EVs are generated using NREL's [EVOLVE tool](#).

Analysis Scenarios *Battery sizing is based on 24-hour outage survival resilience objective	PV Multiplier (Res, Comm) *multiplied with customer peak load (kW) to size PV	Battery Multiplier (Res, Comm) *multiplied with customer peak load (kW) to size battery
Solar Only, Current Model, Base Electrification	(0.547, 2.68)	N/A
Solar + Battery, Current Model, Base Electrification	(1.3088, 2.68)	(0.93, 0.2625)
Solar Only, Upgraded Model, Base Electrification	(0.547, 2.68)	N/A
Solar + Battery, Upgraded Model, Base Electrification	(1.3088, 2.68)	(0.93, 0.2625)
Solar Only, Current Model, Future Electrification	(0.2, 2.68)	N/A
Solar + Battery, Current Model, Future Electrification	(0.86, 2.68)	(0.356, 0.2625)
Solar Only, Upgraded Model, Future Electrification	(0.2, 2.68)	N/A
Solar + Battery, Upgraded Model, Future Electrification	(0.86, 2.68)	(0.356, 0.2625)
Solar + Battery, Current Model, Future Electrification, Electric Vehicles	(0.86, 2.68)	(0.356, 0.2625)
Solar + Battery, Upgraded Model, Future Electrification, Electric Vehicles	(0.86, 2.68)	(0.356, 0.2625)

<sup>1</sup> Oddleifson, Tucker, Kapil Duwadi, Erik Pohl, Patrick Gibbs, Shibani Ghosh, Chrissy Scarpitti, and Liz Weber. 2024. "Prefeasibility Analysis of Behind-the-Meter Distributed Energy Resources in Highland Park, MI." February. <https://www.nrel.gov/docs/fy24osti/87988.pdf>.

# System Average Risk Duration Indices (SARDI): An Overview

- SARDI (System Average Risk Duration Indices) metrics define a system-level risk to quantify the impacts to system performance and reliability affecting customers.
  - SARDI metrics are analogous to the commonly-used reliability index SAIDI (System Average Interruption Duration Index).
- As suggested by the *System Average* prefix to SARDI, this approach calculates an average risk across all customers and all distribution assets.
- Voltage violations\* indicate customers or assets operating at a voltage that is outside of what the industry generally defines as acceptable thresholds. On U.S. power systems, these thresholds often align with the standard from the American National Standards Institute (ANSI), C84.1,<sup>1</sup> and is +/- 5% from nominal values.
- Thermal violations\* indicate an asset that has exceeded its rated capacity. This could be an overloaded overhead wire, underground cable, or transformers. These violations can occur on both the primary (medium-voltage) distribution assets, or the secondary (low-voltage) distribution assets.
- The *risk* on a circuit, as calculated using our SARDI approach, is determined by various factors including:
  - Depth of violation: e.g., 5% overloaded vs. 50% overloaded
  - Duration of violation: e.g., overloaded for 2 hours out of the year vs. 2 hours every day
  - Importance of asset: e.g., If this asset failed, how many customers would be affected? Generally, assets like wires and cables located nearer the substation serve larger numbers of customers and, as such, receive a higher weighting based on downstream customer count.

*\*Unless otherwise stated, grid impact in this study focuses only on voltage violations and thermal overloading of conductors and transformers.<sup>2</sup>*

<sup>1</sup> American National Standards Institute, Inc. 2016. "ANSI C84.1-2016: American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)." American National Standards Institute, Inc.

<sup>2</sup> Duwadi, Kapil, Killian McKenna, Akshay Jain, Kajal Gaur, Adarsh Nagarajan, and David Palchak. 2021. "An Analysis Framework for Distribution Network DER Integration in India: Distributed Solar in Tamil Nadu." *Renewable Energy*, March. <https://www.nrel.gov/docs/fy21osti/78114.pdf>.

# System Average Risk Duration Indices (SARDI): An Overview Cont'd

SARDI metrics can be further split up and calculated for different types of violations on different types of assets. The following are used in this analysis.

- **SARDI Voltage:** Percentage of time duration within the modeling timeframe for which the average customer is at risk of experiencing a voltage violation.
- **SARDI Line:** Percentage of time duration within the modeling timeframe for which the average customer is at risk of experiencing a thermal violation on an upstream overhead wire or underground cable.
- **SARDI Transformer:** Percentage of time duration within the modeling timeframe for which the average customer is at risk of experiencing a thermal violation on an upstream transformer.
- **SARDI Aggregated:** Percentage of time duration within the modeling timeframe for which the average customer is at risk of experiencing *any* type of violation.

$$\text{SARDI}_{\text{voltage}} = \frac{\sum_{t=0}^T N_{VAC}^t \times \Delta T \times 100}{N_c \times T}$$

$$\text{SARDI}_{\text{line}} = \frac{\sum_{t=0}^T N_{LAC}^t \times \Delta T \times 100}{N_c \times T}$$

$$\text{SARDI}_{\text{transformer}} = \frac{\sum_{t=0}^T N_{TAC}^t \times \Delta T \times 100}{N_c \times T}$$

$$\text{SARDI}_{\text{aggregated}} = \frac{\sum_{t=0}^T N_{AC}^t \times \Delta T \times 100}{N_c \times T}$$

- $N_{VAC}^t$  = number of unique customers affected by voltage violation  
 $N_{LAC}^t$  = number of unique customers affected by line overload  
 $N_{TAC}^t$  = number of unique customers affected by xfmr overload  
 $N_{AC}^t$  = number of unique customers affected by voltage, line, or transformer violation  
 $\Delta T$  = simulation timestep  
 $N_c$  = total number of customers

# Generalized Grid Impacts from Distributed Energy Resources

- **Voltage Impacts:**
  - While loads (energy consumption) pull system voltages *down* and can result in undervoltages (voltages *below* the minimum acceptable tolerance), distributed energy generation at the grid edge has the opposite effect, raising voltages most severely at their point of connection (often referred to as the point of common coupling or PCC). The extent of these effects are determined by a number of factors including the location on the grid, size of the DER, ratio of distributed generation to load at a given time, and system impedances. This effect is generally more pronounced during periods with relatively low load, when more solar generation is pushed back onto the grid rather than consumed onsite. It is not uncommon for utility engineers and power-system modelers to look at a worst-case scenario when studying DER grid impacts which is often when loads are at a minimum and distributed generation is at a maximum (also referred to as minimum daytime load or MDL).
- **Thermal Loading Impacts:**
  - Adding distributed generation can reduce the loading of grid assets as they can produce energy at the location at which it is consumed rather than requiring the load to draw from the grid. However, at high adoption levels or when energy demand does not coincide with high solar production, the reverse power flow from distributed generation can *increase* loading on assets in the opposite direction.
  - **System Losses:**
  - Distributed generation has the potential to reduce system losses by providing energy generation at the same location at which it is consumed, reducing the power drawn from the grid. At especially high adoption levels, or on circuits where energy demand does not coincide with high solar production hours, the reverse power flow from distributed generation can *increase* losses as well.
- **DER Impacts not explored in this study:**
  - System protection, grid reliability, system operations, switching procedures, or effects on the bulk power system stability and reliability.

# Assumptions in Distribution Modeling

- **Significant assumptions:**
  - The average load profiles used represent a "typical" residential and commercial customer, provided by DTE, and are applied to *all* loads in each customer class. In reality, every customer load profile varies, which would ultimately affect the coincident peak demand seen on segments of the feeder and individual grid assets. Unique customer loads profiles can only be captured through fine-time-resolution data from advanced metering infrastructure (AMI) or other recording meter.
  - Peak load allocation algorithms in [CYME](#) modeling software are used to find out the peak load for each customers based on substation SCADA and individual monthly energy consumption. In reality, *energy* consumption is not a perfect indicator of peak *power* demand.
  - For secondary modeling we mapped spot loads from [CYME](#) to buildings available from Open Street data and [Microsoft Parcel Data](#). There may be a mismatch in the number, location, or size of buildings, resulting in potentially inaccurate load-flow results or customer counts.
  - The analysis tools used in this study (EVOLVE, EMERGE, and REopt) also include assumptions regarding typical customer behaviors, geographic patterns of DERs adoption, and technical characteristics of DERs. Given the inherent uncertainties in predicting these items and the lack of granular, locationally accurate datasets to inform this study, these assumptions may differ from the actual current and future conditions within Highland Park.
  - As mentioned on the previous slide, there are multiple types of DER impacts not explored in this study.
- **Interpretation of study results:**
  - The results of this study can reasonably illustrate high-level trends under the scenarios we generate, but in general cannot pinpoint the more granular impacts on individual lines, transformers, or single customers.
  - Scenarios can forecast changes to customer loads profiles based on a set of initial conditions and assumptions but cannot predict the future with a high degree of certainty.
  - Results can also reasonably illustrate the *types* of violations on a system (i.e., namely impacts on the secondary (low-voltage) networks rather than primary networks, or voltage impacts instead of thermal overloads). These findings can provide valuable insights for utility planning, design, and operations.

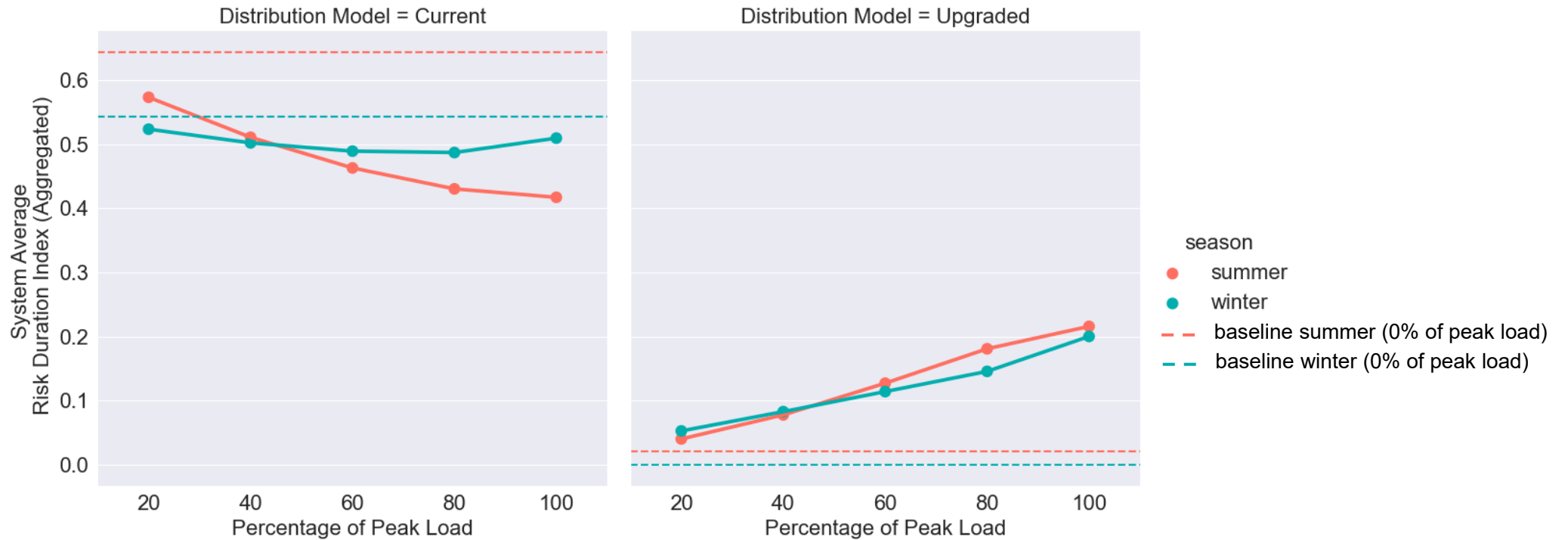
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# Scenario Analysis Results

# **Rooftop Solar Only (Base Electrification): Grid Impacts**

# Rooftop Solar (Base Electrification): SARDI Aggregated

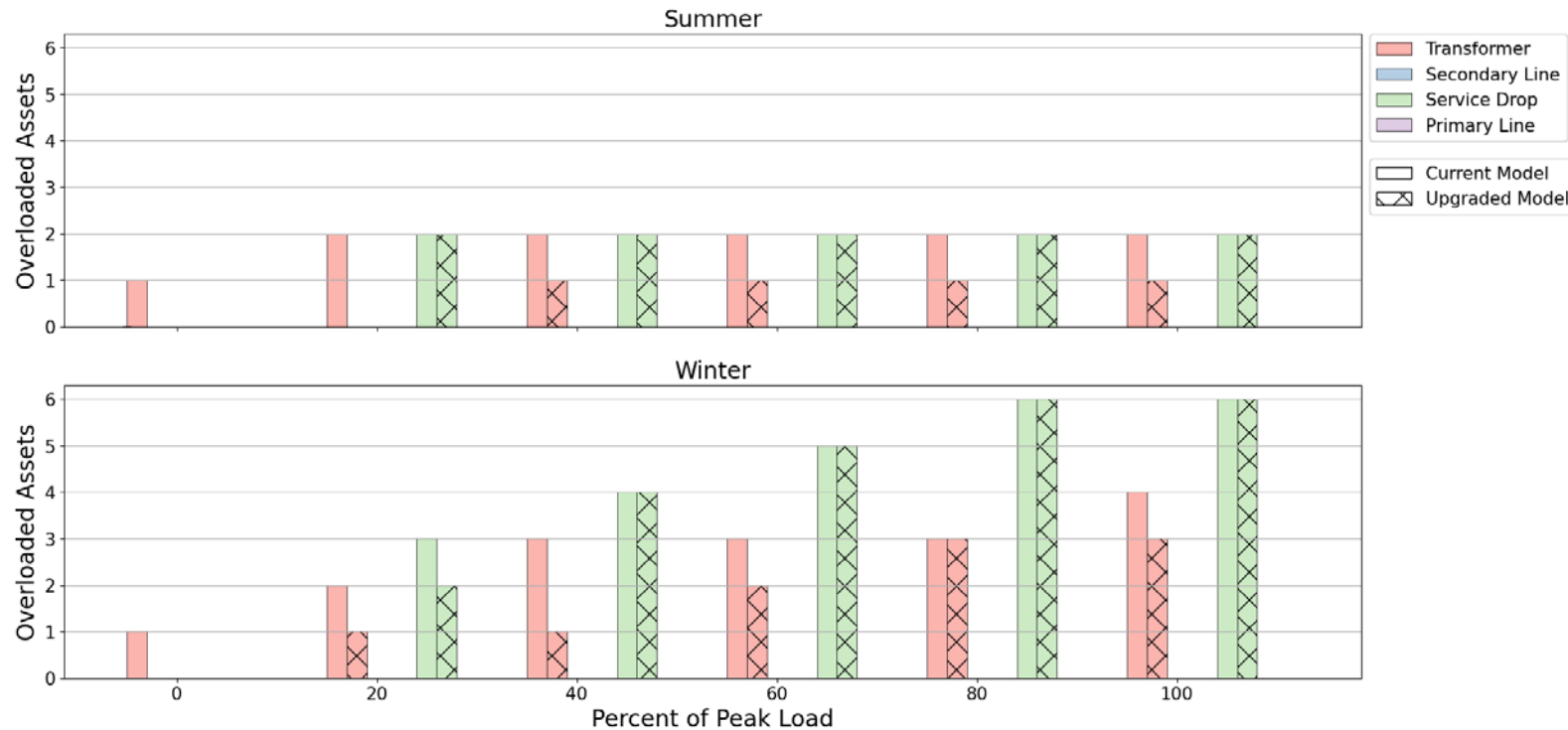
The SARDI aggregated metric is relatively small for our solar-only scenario under the current base electrification. With no solar added to our Current Model, we see a baseline risk of roughly 0.65% and 0.55% in summer and winter, respectively. As we add solar to our Current Model, system-level risk tends to decrease, rising slightly at high adoption rates in the winter. On the Upgraded Model, we start from a lower baseline of near 0% for both summer and winter and see an increase in risk with increasing solar adoption, though overall, a lower risk across all adoption levels compared to our Current Model. Note this risk is mainly due to thermal overloading of lines and/or transformers. We did not observe voltage violations in these scenarios.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average SARDI ranking across 25 simulation samples.

# Rooftop Solar (Base Electrification): Number of Overloaded Assets

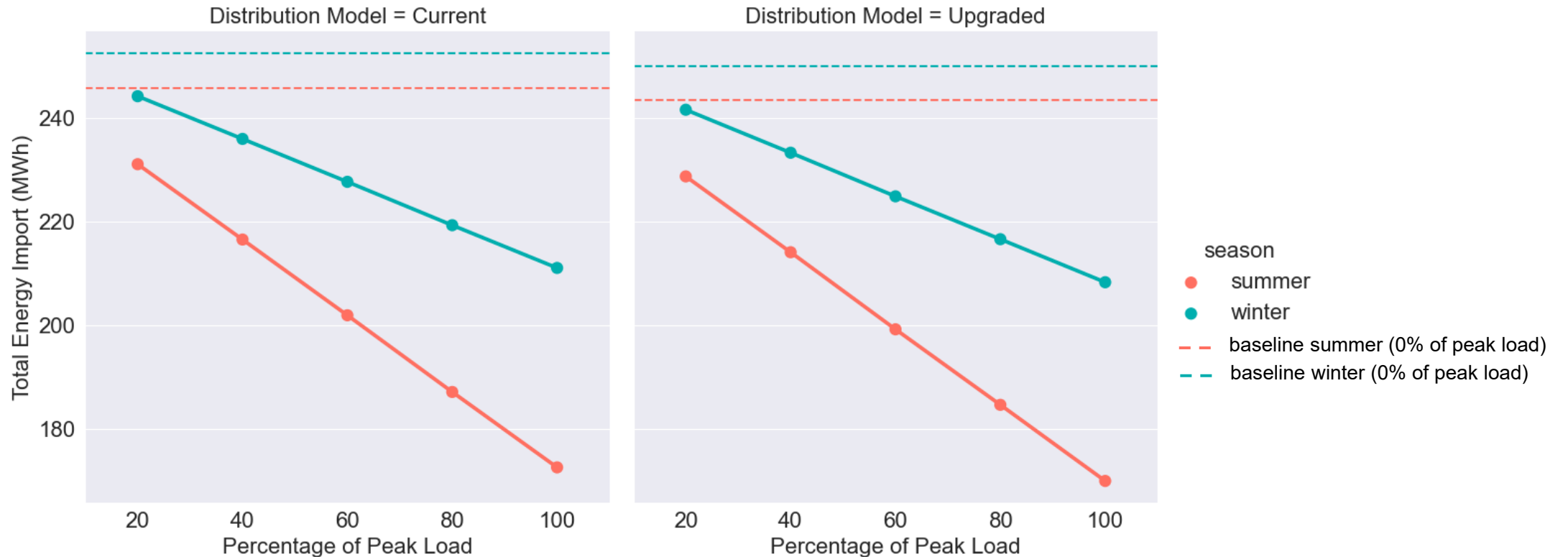
The relatively low SARDI score is further reflected in the small number of overloaded assets shown below. Overloads are exclusive to a handful of transformers and service drops and tend to improve or stay the same when upgrading the system. It is important to recognize that despite upgrading our feeder from 4.8 kV to 13.2 kV, the voltages of our secondary (low-voltage) lines do not change (120/240V in both models) and so the improvements here are relatively small and namely reflect changes in transformer sizes in select cases (i.e., when the existing transformer had a capacity of less than 50 kVA). There are no overloaded primary lines, even at 100% solar adoption. There are generally more overloaded assets in the wintertime (bottom) due to lower energy demand and higher back feed of solar generation onto the distribution network, illustrated particularly at high levels of solar adoption.



Percentage of Peak Load is defined as % of peak before introducing distributed energy resources. The bar plots shown take the max number of overloaded assets across 25 simulation samples.

# Rooftop Solar (Base Electrification): Total Energy Import

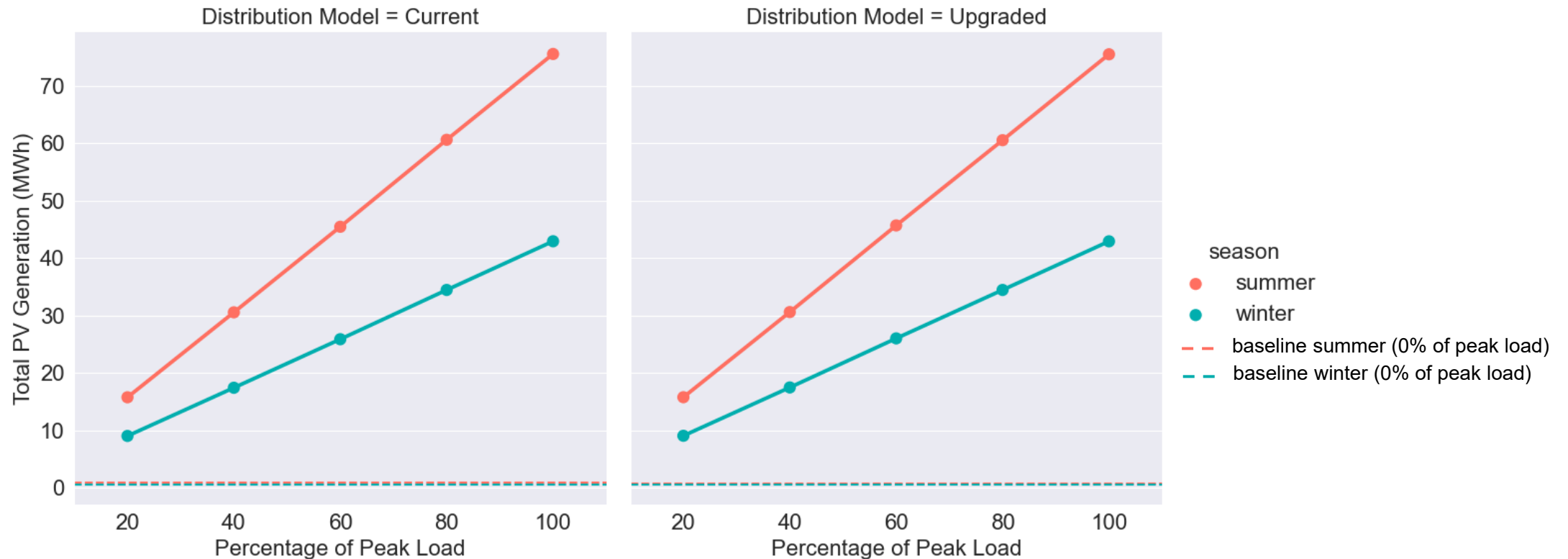
As one would expect, energy import (energy produced by bulk system generation and transported across high-voltage transmission networks) reduces with increasing distributed solar adoption. We see a greater reduction during the summer due to increased irradiance from the sun and more daylight hours. The further reduction in imports (albeit very slight) we see on our Upgraded Model is due to reduced line and transformer losses in the upgraded system, illustrated in more detail on slide 27.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average SARDI ranking across 25 simulation samples.

# Rooftop Solar (Base Electrification): Total PV Generation

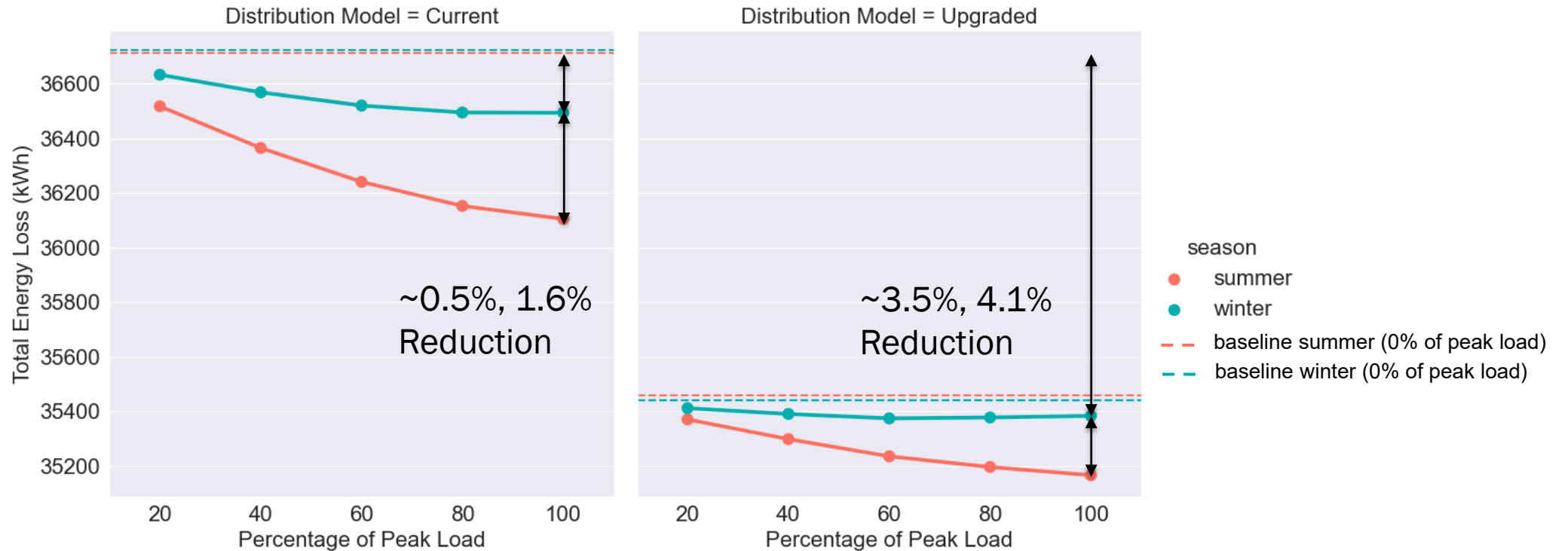
Conversely to energy imports, distributed solar generation increases with increasing solar adoption. We see higher solar generation in the summer due to higher solar irradiance and longer days. Here there is no difference in generation between our Current and Upgraded Models because the peak load (and thus the assigned solar system sizes) is the same in both models for the current electrification scenario.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average SARDI ranking across 25 simulation samples.

# Rooftop Solar (Base Electrification): System Losses

System losses tend to reduce with increasing solar adoption as confirmed by the plots below. In our Current Model, we see a peak loss reduction of about 0.5% and 1.6% at 100% solar adoption in the winter and summer, respectively, compared to the baseline. The Upgraded Model sees a *further* reduction in losses for a peak of 3.5% and 4.1% reductions for winter and summer, respectively, when compared to baseline in our Current Model. The additional reduction is largely resultant from lower current flow due to operating at a higher voltage class, as well as larger assets with lower impedances per DTE's upgrade design guidance (see slide 14). For reference, the Current Model's system losses with no solar adoption is ~36.7 MWh (winter) or ~14.7% of energy imported (winter). The Upgraded Model's system losses are ~35.4 MWh (winter) or ~14.1% of energy imported (winter).



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average SARDI ranking across 25 simulation samples.

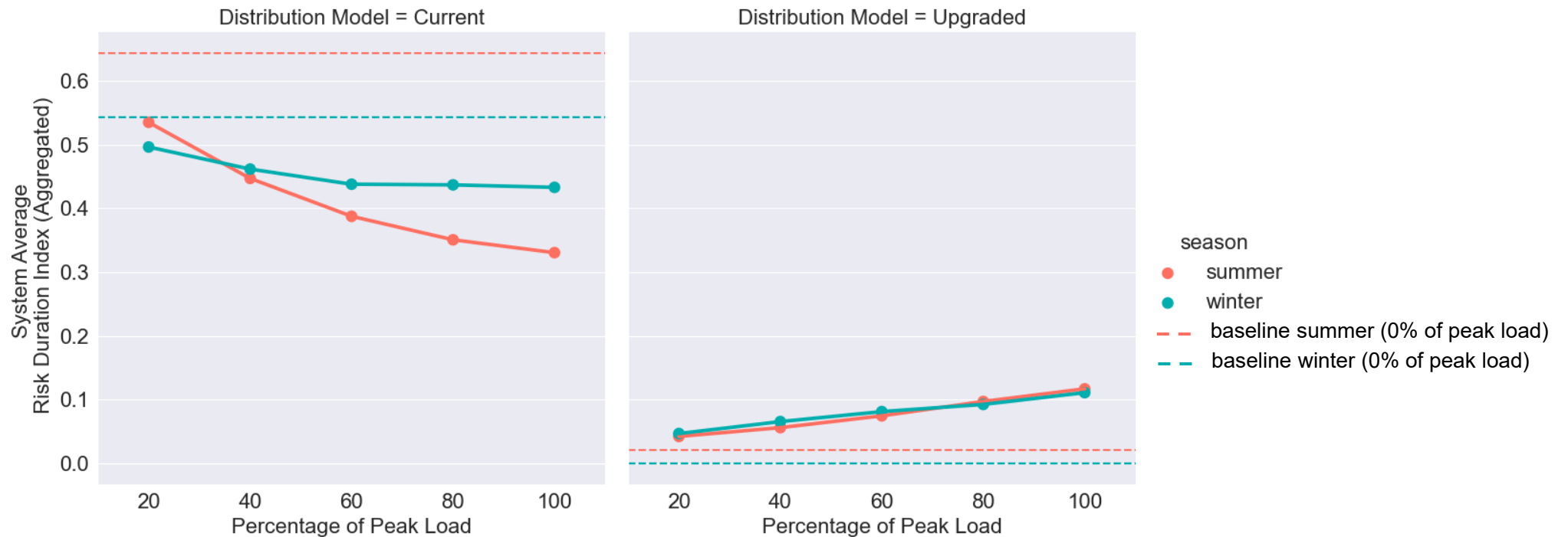
# Key Takeaways

- While only minimal system risks are seen in this solar-only scenario, the SARDI aggregated metric shows that adding rooftop solar generally reduces the risk associated with asset overloading in the current model.
- Adding solar in the upgraded model increases overall system risk, though values are still lower than what the *current* grid is experiencing.
- All overloaded assets, with and without solar, are limited to the low-voltage secondary distribution network (from distribution transformer to customer meter), a trend which continues throughout this analysis illustrated on the following slides. No thermal impacts are seen on the medium-voltage primary network.
- Assuming customers would choose this cost-optimal solar size (as recommended by REopt), total energy import would be reduced by about 24% in summer and 14% in winter with a 100% solar adoption level.
- The adoption of distributed solar reduces energy losses by up to 1.6% on the current system and up to 4.1% in the upgraded feeder, when compared with the current model baseline.

# **Rooftop Solar and Energy Storage (Base Electrification): Grid Impacts**

# Rooftop Solar and Energy Storage (Base Electrification): SARDI Aggregated

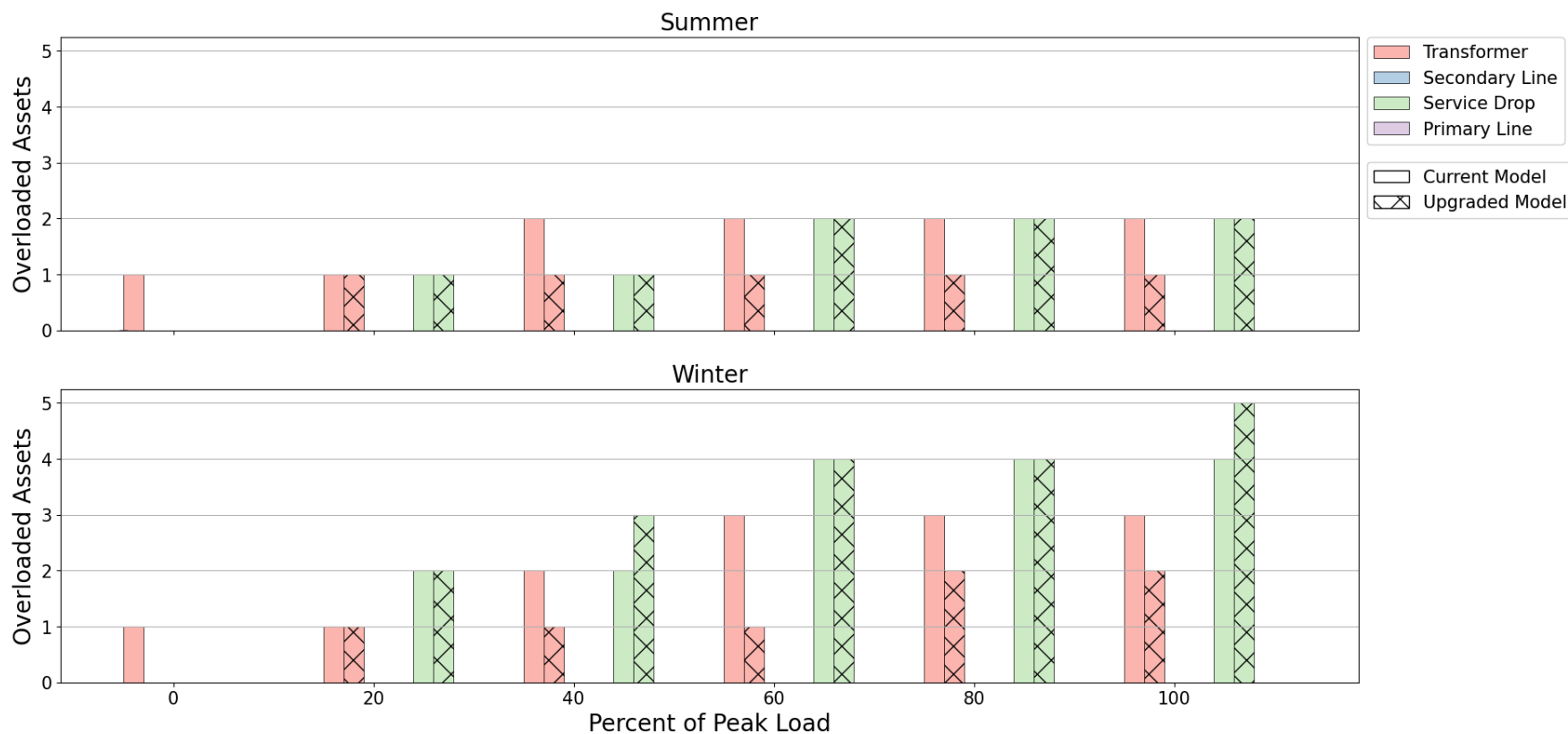
In our solar + storage scenario, we see almost identical trends to our solar-only model shown previously. We see small overall risk levels of about 0.65% in our baseline, decreasing with higher solar adoption levels and overall lower risk levels in our Upgraded Model. The slight improvements from added energy storage are illustrated on a later slide in more detail. Note, this risk is mainly due to thermal overloading of line and/or transformers. We did not observe voltage violations in these scenarios.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Base Electrification): Number of Overloaded Assets

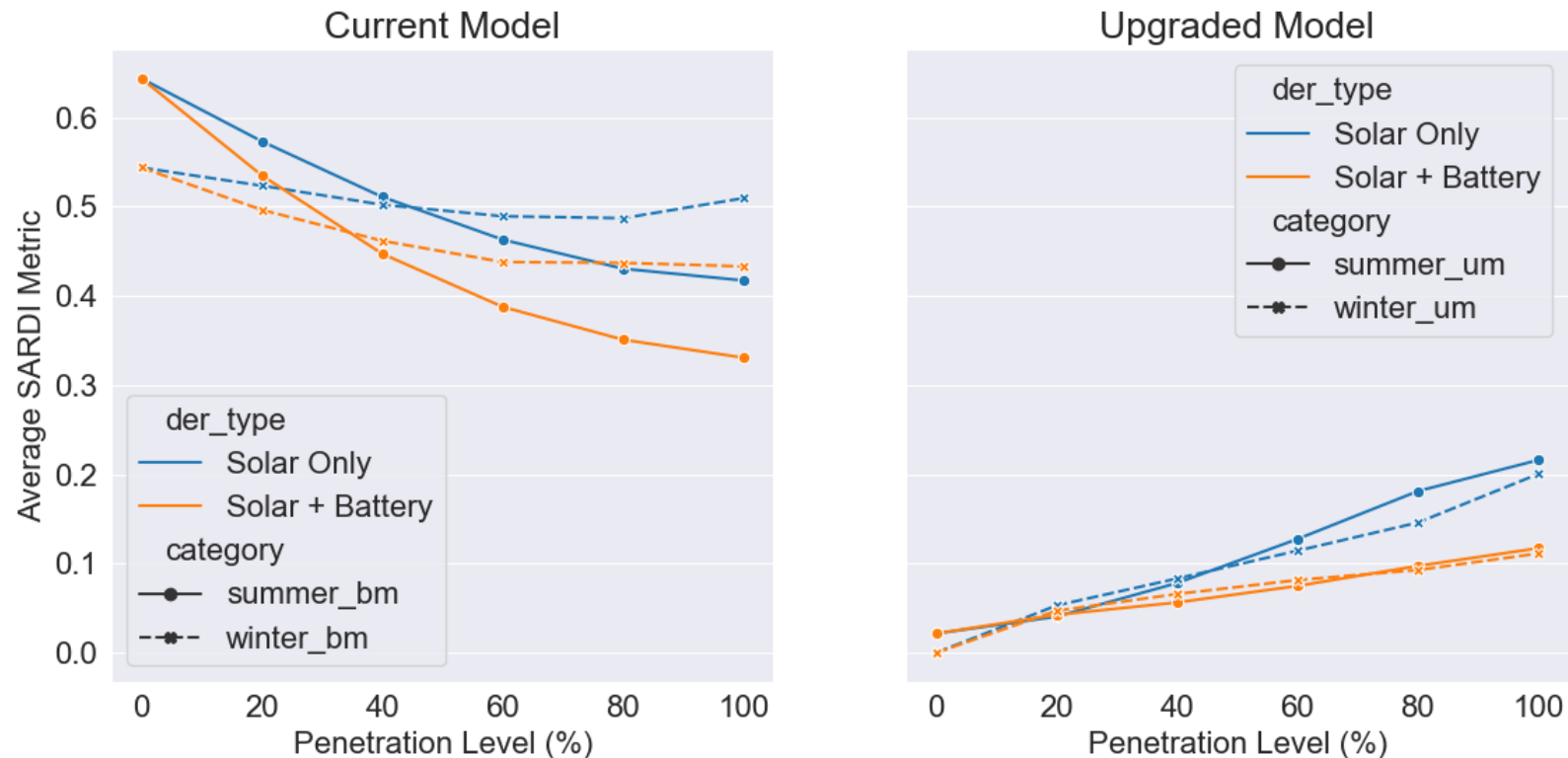
We see an almost identical number of overloaded assets compared with our solar-only model with the addition of energy storage. At high levels of adoption, we see a slight reduction in overloaded assets, illustrated in more detail on the following slide.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The bar plots shown take the max number of overloaded assets across 25 simulation samples.

# Solar vs. Solar and Energy Storage (Base Electrification): Comparison

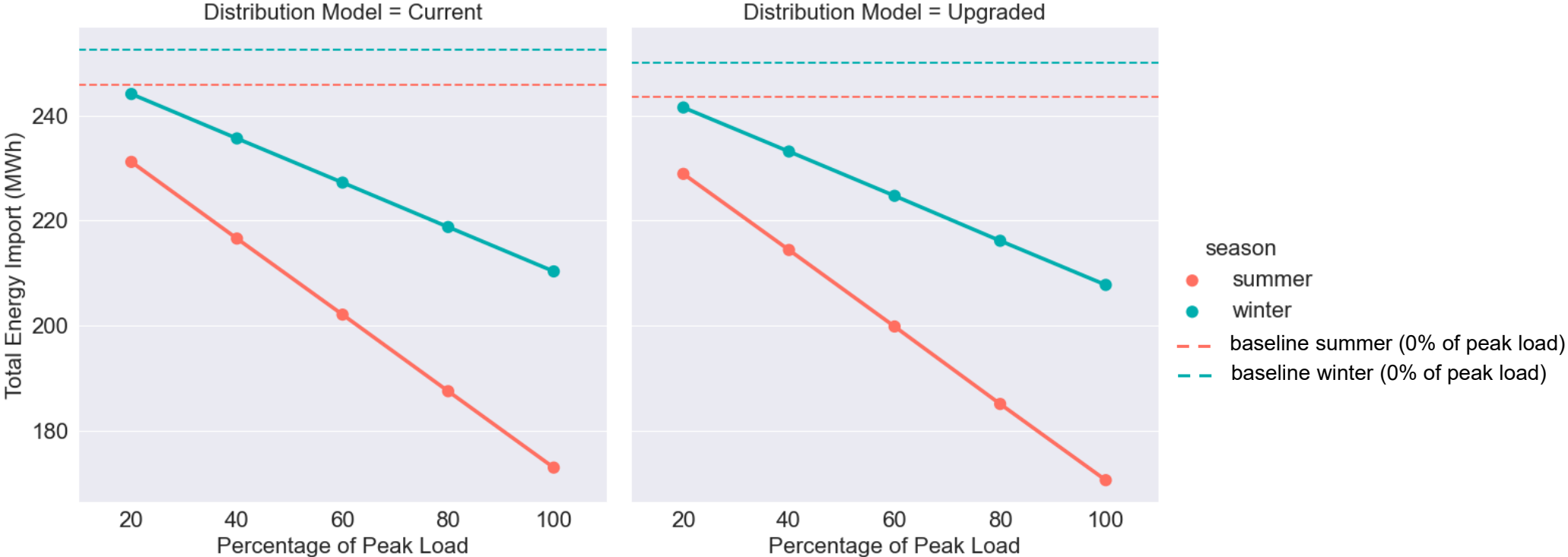
Incorporating behind-the-meter energy storage in our models further reduces system risk in both the Current and Upgraded models. The added storage enables homeowners to consume more of the energy their rooftop solar generates by storing energy during periods of low load, rather than exporting energy back onto the distribution system. This ultimately results in fewer solar-caused violations and the associated risks.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Base Electrification): Total Energy Import

We see almost identical trends to our solar-only model, illustrating that behind-the-meter energy storage, as we have implemented it, does not have major impacts on overall energy consumption from the bulk power system. Batteries may charge from onsite solar or from the grid, however, given that this stored energy is discharged at a later time, we see no net changes in overall energy consumption, compared with the solar-only scenario.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Base Electrification): Total PV Generation

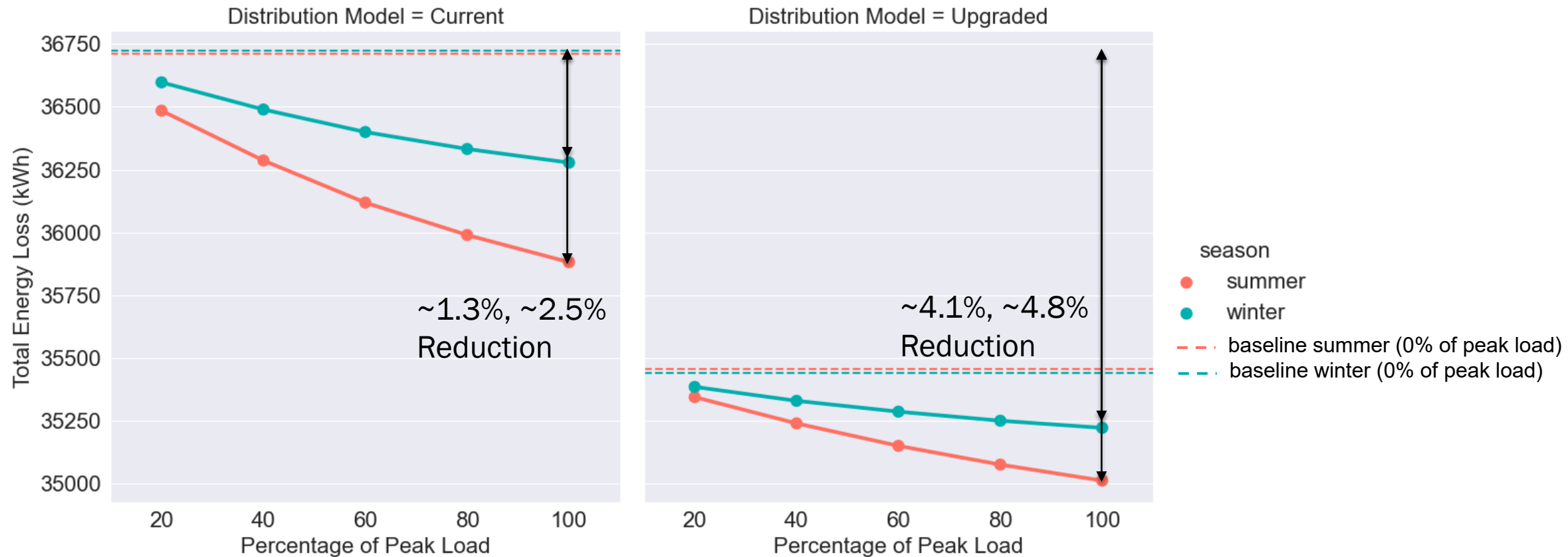
Our modeling of PV systems does not change between our solar-only vs. solar + storage models. As such, we see no differences in generation from PV compared across the two scenarios.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Base Electrification): System Losses

Adding behind-the-meter energy storage results in slight improvements in system losses when compared to our solar model, due largely to a reduction in solar exports and increased onsite consumption. The additional loss reduction is, albeit, slight, with a peak reduction of 2.5% vs. 1.3% and 4.8% vs. 4.1% in our Current and Upgraded models, respectively.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Key Takeaways

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- Again, while only minimal system risks are seen in this scenario, the SARDI aggregated metric shows that adding energy storage alongside rooftop solar can further reduce risk.
- Overloaded assets are exclusive to the low-voltage network and service transformers. No impacts to the medium-voltage primary network are seen.
- Adding behind-the-meter energy storage results in slight improvements in system losses when compared to our solar scenario, due largely to a reduction in solar exports and increased onsite consumption.
- Overall, the current 4.8 kV system does not appear to be a severe limitation to the adoption of distributed cost-optimal rooftop solar plus behind-the-meter storage systems for this region of Highland Park. Larger rooftop solar systems or utility-scale installations may be more limited by the legacy distribution voltage class.

# **Rooftop Solar Only (Future Electrification): Grid Impacts**

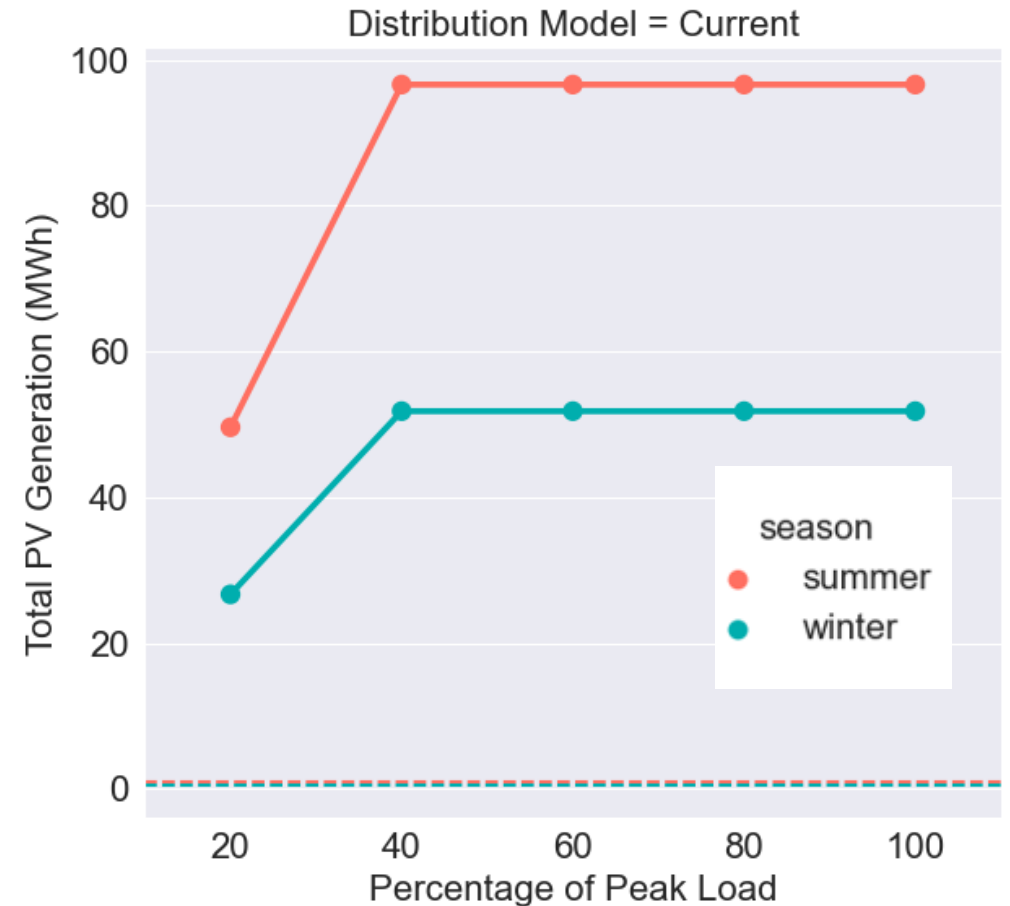
# Rooftop Solar (Future Electrification): Notes

A nuance of our scenario development approach, seen in our Rooftop Solar (Future Electrification) scenario is shown in the plot of total PV generation.

**With the added loads of building electrification, we cannot meet more than 40% of the system peak load with cost-optimal rooftop solar installed at every residence.** This results in a leveling off of solar generation and the resulting risk metrics beyond 40% adoption. This result is due, in part, to the relatively small individual solar PV systems installed at each house, prescribed as the cost-optimal size from the accompanying REopt analysis.

Additionally, the overall much higher loads from electrified heating produces a circuit where to meet 40% of the system peak load in installed solar capacity using cost-optimal system sizes, 100% of customers on this circuit need to have solar installed. Beyond this point, there are physically no more rooftops on which to install more solar, and as such, solar generation and the risk metrics do not change beyond this point. Details on why the smaller PV systems are still the cost-optimal option are presented in the accompanying presentation describing the REopt analysis.<sup>1</sup>

One should also note that nearly all the increased energy consumption due to electrification occurs in the wintertime. As such, summer metrics are relatively unchanged from previously shown scenarios. This trend will largely hold true for the remaining future electrification scenarios.

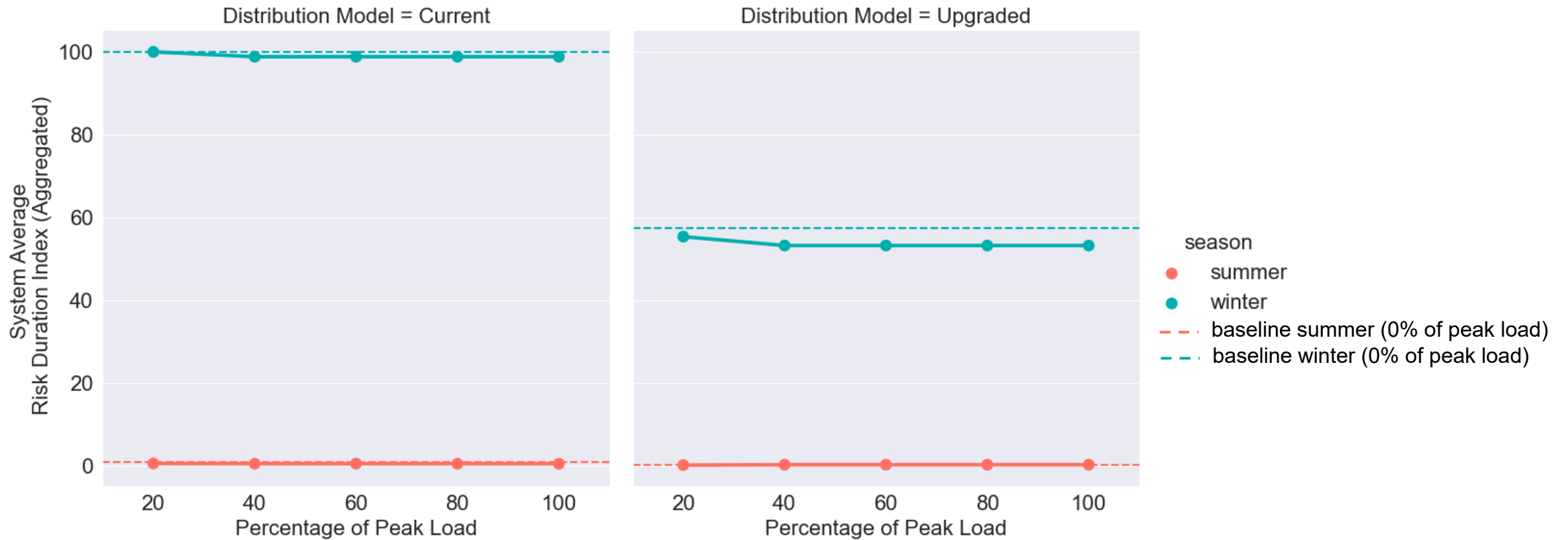


*Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.*

<sup>1</sup> Oddleifson, Tucker, Kapil Duwadi, Erik Pohl, Patrick Gibbs, Shibani Ghosh, Chrissy Scarpitti, and Liz Weber. 2024. "Prefeasibility Analysis of Behind-the-Meter Distributed Energy Resources in Highland Park, MI." February. <https://www.nrel.gov/docs/fy24osti/87988.pdf>.

# Rooftop Solar (Future Electrification): SARDI Aggregated

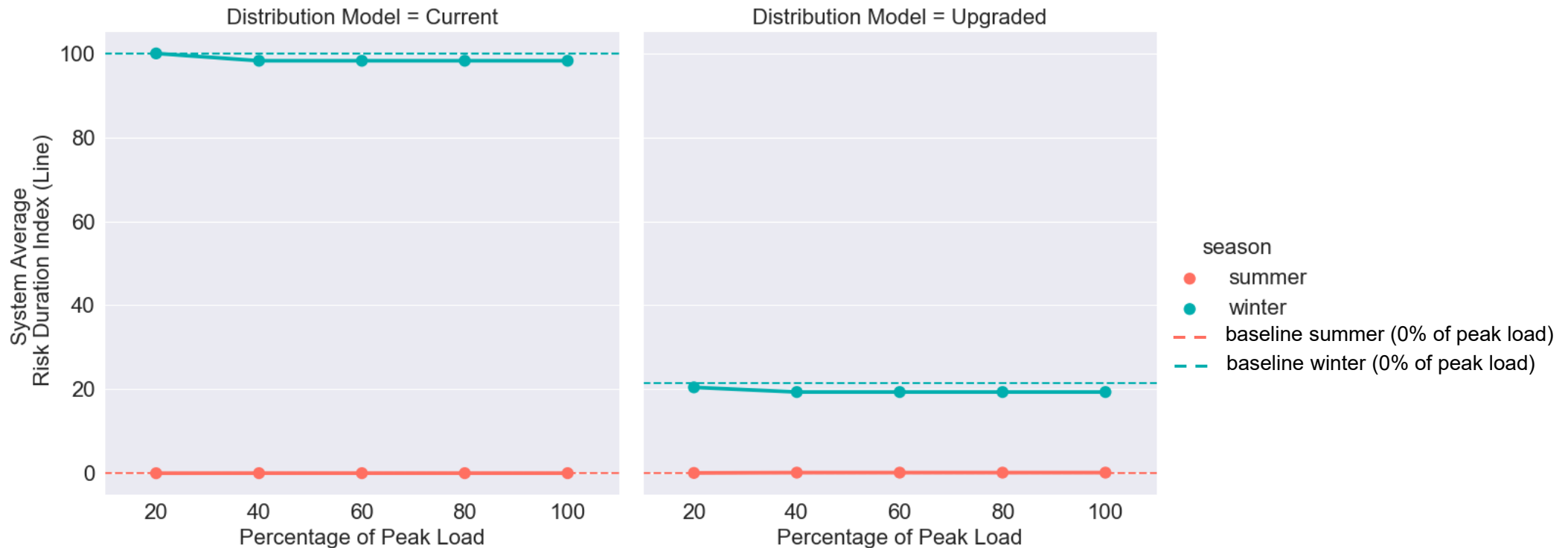
The added loads in our Future Electrification scenarios result in far higher risk levels during the winter months, when electric heating loads are present. A SARDI Aggregated score of 100 indicates that 100% of the customers are located downstream of an at-risk asset for 100% of the modeling timeframe. The significant drop in SARDI Aggregated score in the Upgraded model is driven primarily by a reduction in line overloads. The following slides provide a more detailed breakdown of this score.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The bar plots shown take the max number of overloaded assets across 25 simulation samples.

# Rooftop Solar (Future Electrification): SARDI Line

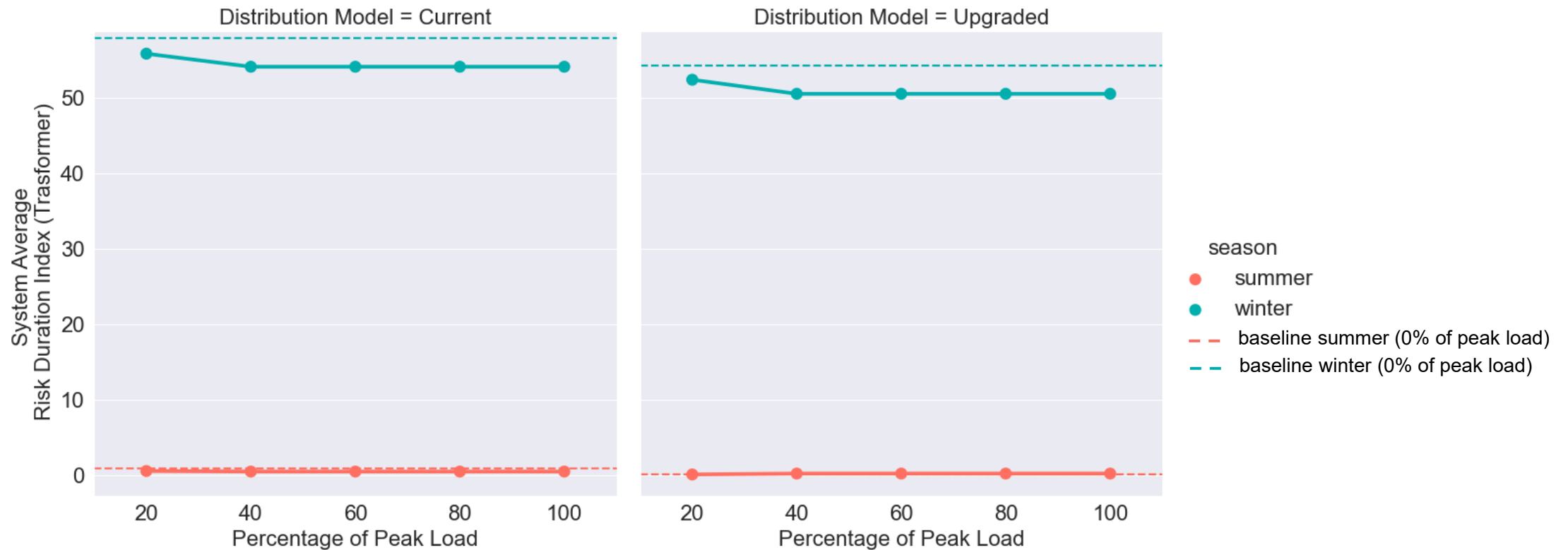
The high SARDI Aggregated score is driven in a large part by overloaded cables and wires, including central assets located in close proximity to the substation. On our Current Model, we see practically no changes to our summer risk levels (once again, almost zero). During the winter, we see an initial SARDI Line of 100%, followed by a slight decrease as solar alleviates some of these overloads until reaching saturation around 40% peak load. Once upgraded to a higher voltage class, we see a substantial drop in SARDI Line, with most remaining violations being located on the low-voltage networks. The remaining risks are indicative of potentially inadequate design standards if planning for a high-electrification future.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar (Future Electrification): SARDI Transformer

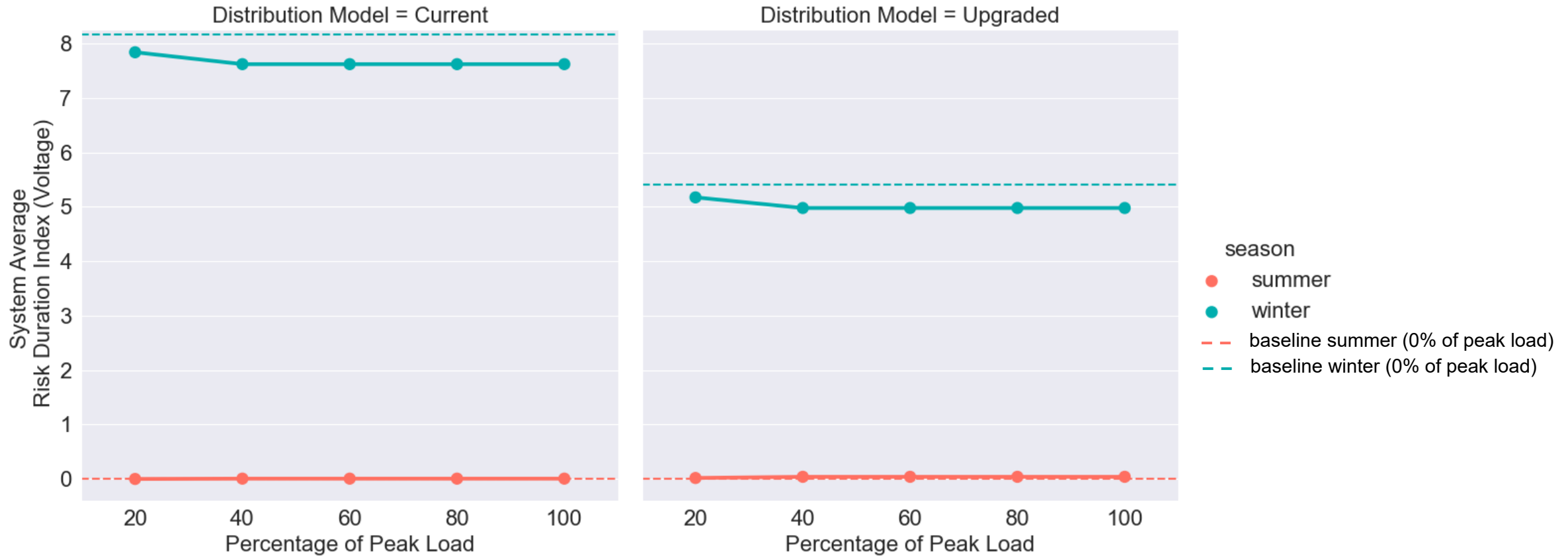
While our Upgraded Model includes larger transformers for those that were previously less than 50 kVA (replaced with a 50 kVA), the persistent high SARDI Transformer score in our Upgraded Model indicates that this rule of thumb may not be sufficient for high-electrification futures. The result suggests that further upgrades (i.e., swapping 50 kVA to 100 kVA transformers or splitting up customer counts onto *additional* transformers) may be needed to accommodate larger household loads.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar (Future Electrification): SARDI Voltage

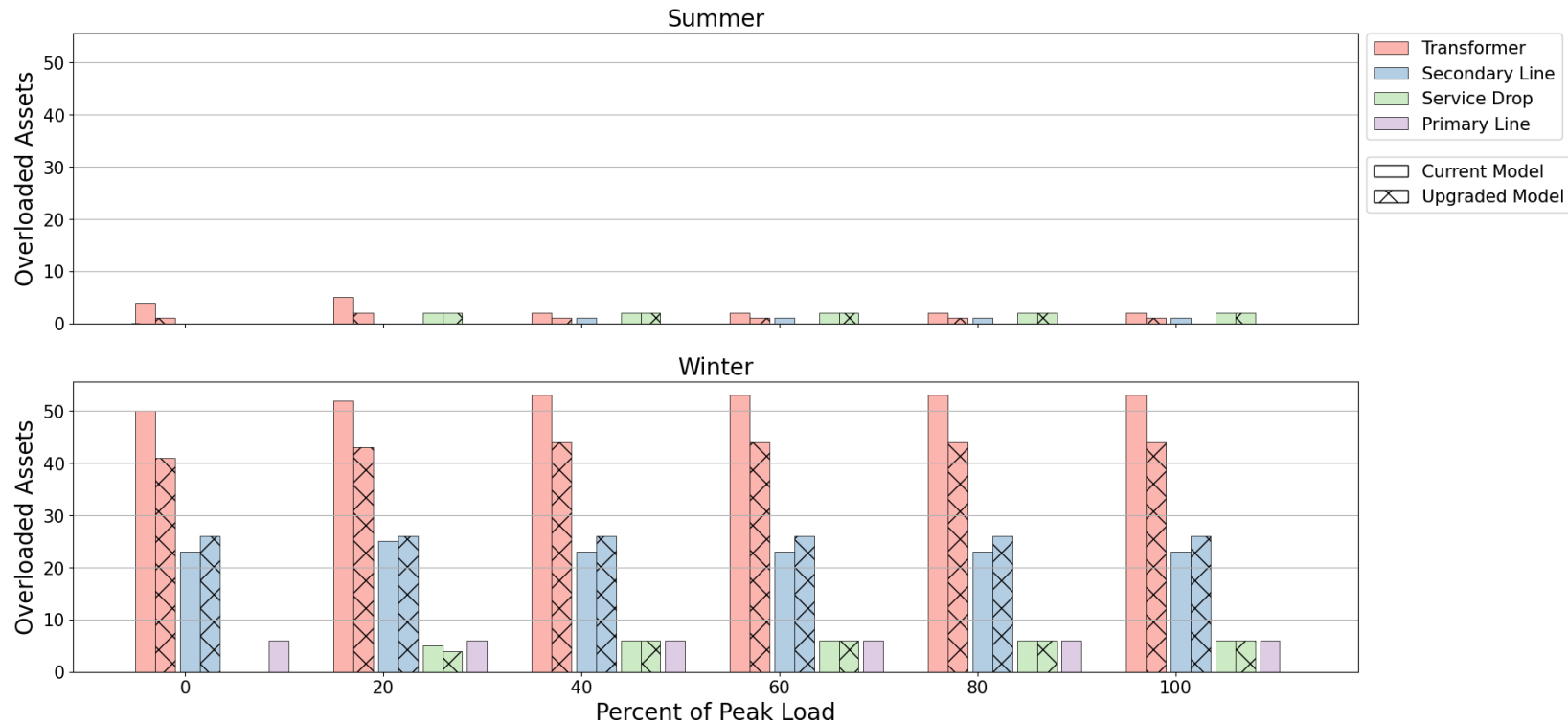
Our SARDI Voltage score in this scenario is relatively low, indicating that line ampacities and transformer kVA ratings are the main bottleneck for high-electrification futures. That said, the findings below illustrating persistent voltage violations after upgrading can still inform future design standards, possibly prescribing larger secondaries, added voltage regulation, or additional transformers to limit overall secondary lengths and resulting voltage drop.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar (Future Electrification): Number of Overloaded Assets

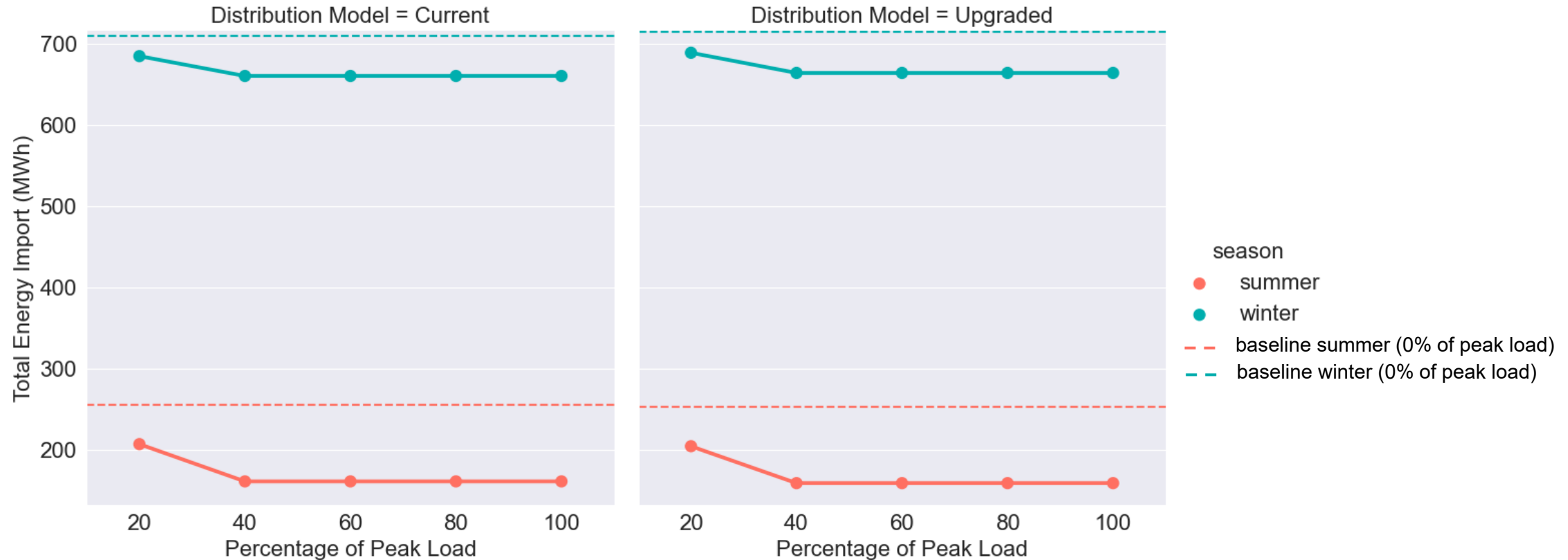
In our Future Electrification models, we see a much larger number of overloaded service transformers and secondary lines, almost exclusively in the wintertime. As previously noted, there are primary lines near the feeder head in our Current Model which are overloaded resulting in a SARDI Line of 100. While these primary line violations are remedied in our upgraded model, the majority of the overloaded service transformers, secondary lines and service drops remain overloaded in our upgraded model, again illustrating the need for more robust design standards if planning for a high-electrification future.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The bar plots shown take the max number of overloaded assets across 25 simulation samples.

# Rooftop Solar (Future Electrification): Total Energy Imports

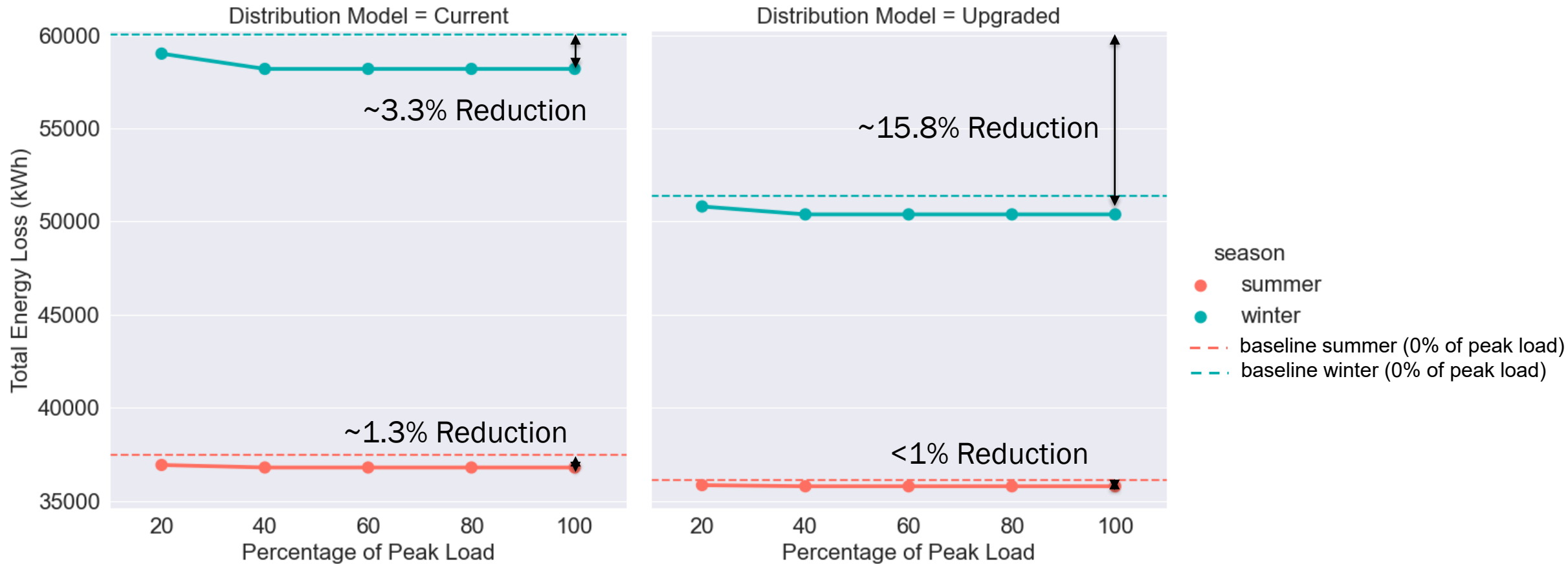
We see a dramatic increase in energy import (nearly 3X) in the wintertime due mainly to electric heating loads, and practically no increase in summertime consumption.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar (Future Electrification): System Losses

The significantly higher losses are a result of much higher loads from building electrification and wintertime heating loads. We see a large improvement in system losses when upgrading the circuit to a higher voltage class.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

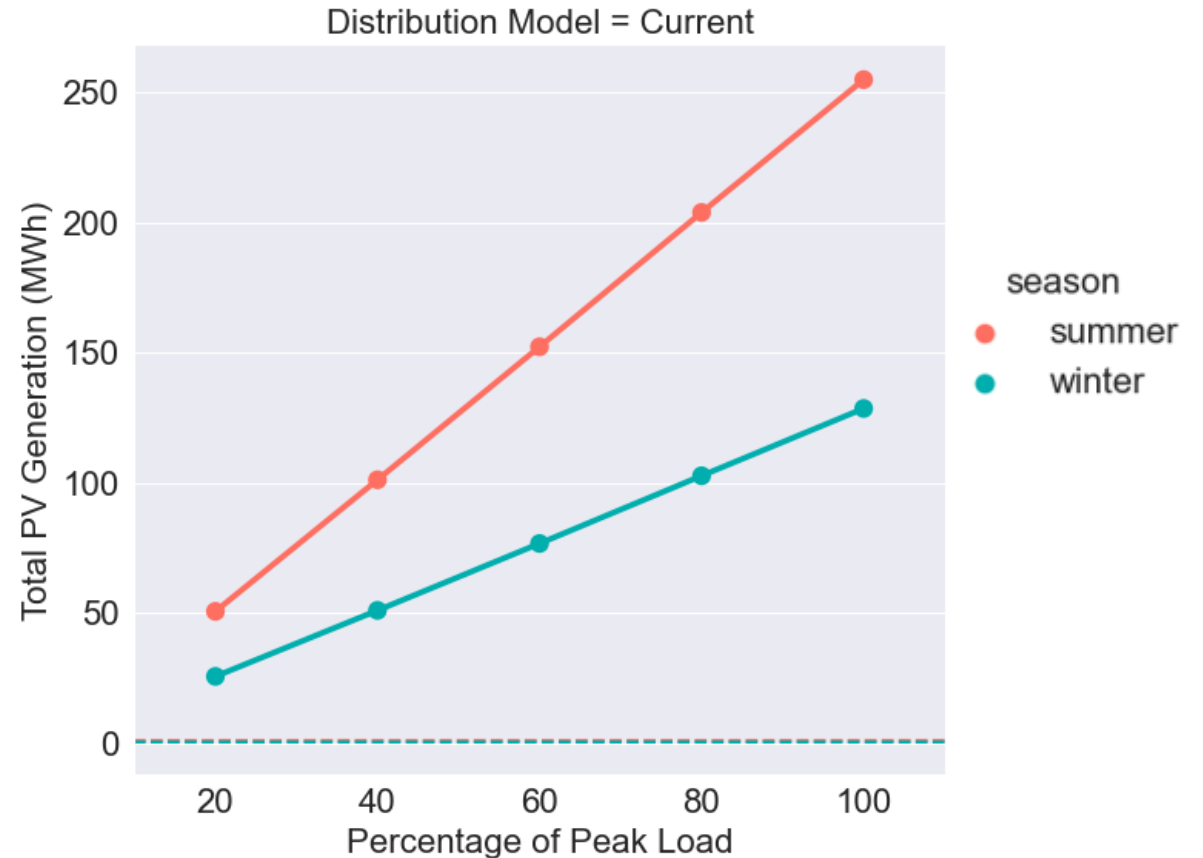
# Key Takeaways

- Significant load increases in our Future Electrification scenarios drastically increase the baseline system risk. This effect takes place almost exclusively in the wintertime, with little change in the summertime, due to the addition of electric heating loads, in place of gas furnaces.
- With no solar, we see a SARDI aggregated metric of 100, indicating that all customers are served by an at-risk asset for the duration of the modeling timeframe.
- The cost-optimal solar sizing algorithm used in REopt results in relatively small solar installations on each house when compared with the large increase in winter loading. This creates a saturation effect, around 40% adoption, at which point every house has solar installed. As a result, increasing solar adoption beyond this point is not possible, and risk metrics remain constant beyond this point.
- Upgrading the system produces large improvements in risks and system losses, however significant system risks remain on the Upgraded Model, namely in the form of overloaded secondary lines and overloaded transformers.
- Remaining high risk metrics in our upgraded model indicate the need for revised utility design standards, particularly for secondary systems. Revisions may include larger standard secondary conductors, fewer customers per transformer, or adding additional transformers to limit secondary lengths.

# **Rooftop Solar and Energy Storage (Future Electrification): Grid Impacts**

# Rooftop Solar and Energy Storage (Future Electrification): Notes

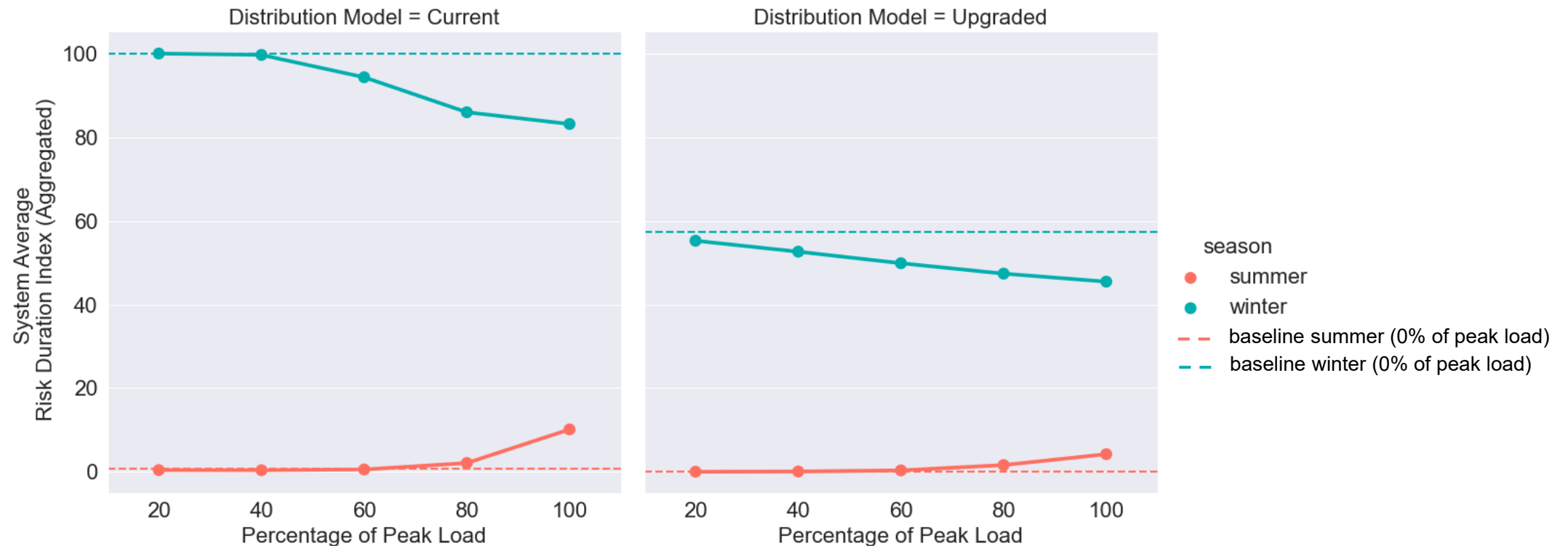
A notable difference resulting from the addition of energy storage, is that it increases the cost-optimal solar size recommended by REopt. As a result, we no longer see the saturation effect causing solar generation to level out, as we did in the previous solar-only scenario. This means that we can effectively meet even 100% of the system peak load with installed solar capacity, thanks to the increased self-consumption enabled by energy storage and larger individual solar installations. This phenomenon and solar sizing strategies are explained in more detail in the accompanying REopt analysis.



*Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.*

# Rooftop Solar and Energy Storage (Future Electrification): SARDI Aggregated

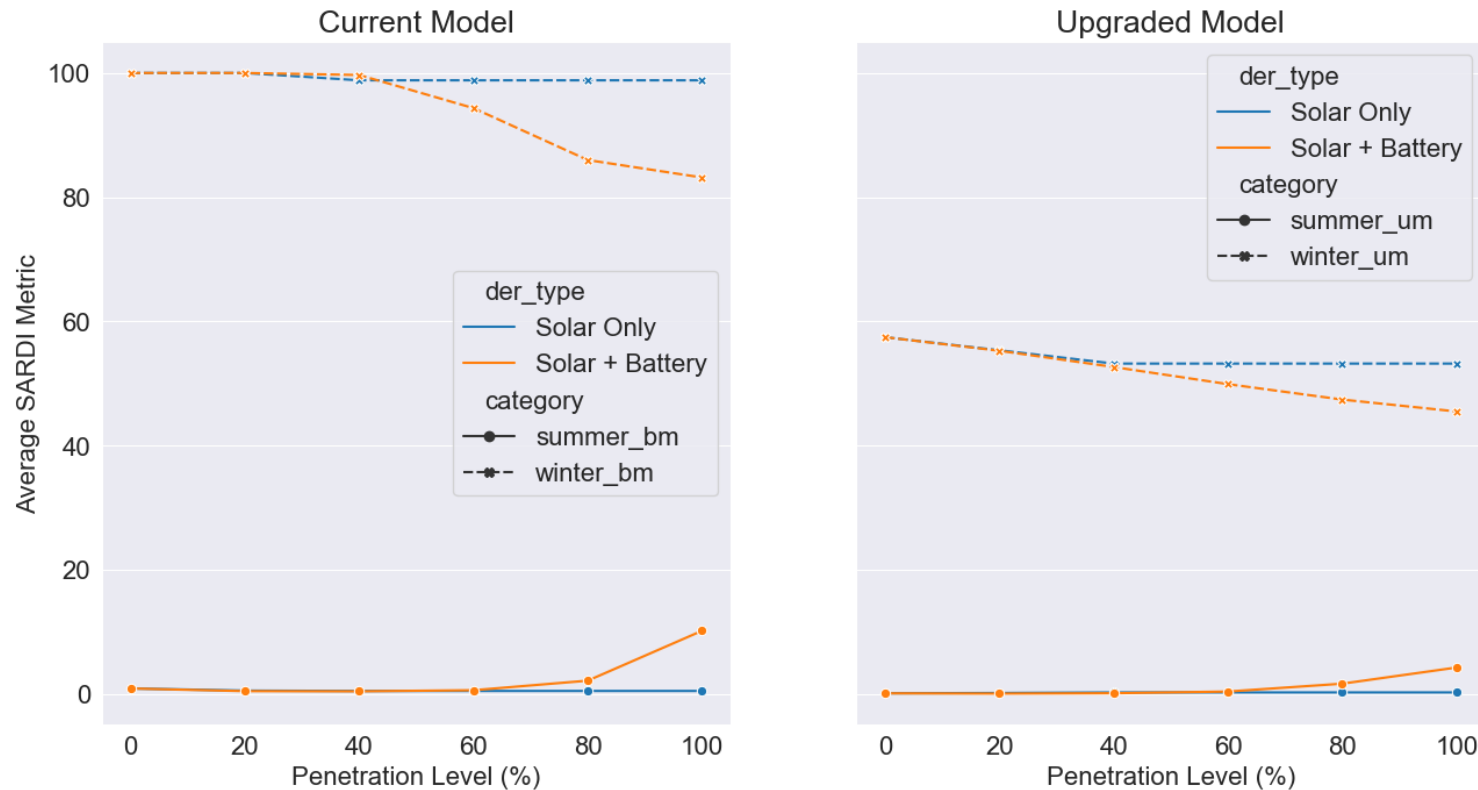
In contrast to our solar-only scenario, we see a consistent decrease in our wintertime risk with increasing solar adoption in both models. The opposite is true in the summertime. PV systems which are sized to accommodate the larger winter loads and energy storage will export more to the grid during the summertime given the higher irradiance and lower loads in the absence of electric heating. As such, at high levels of adoption, we see an uptick in risk. Our Upgraded Model overall shows a lower risk level, but similar to the solar-only scenario, there are still non-zero risks.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): Comparison

The comparison plots below show that adding energy storage, and enabling larger cost-optimal PV systems increases the benefits we see from DERs in the winter. At the same time, these large PV systems end up increasing risk in the summer at high adoption levels by causing a combination of overvoltages and asset overloading from energy export.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): SARDI Transformer

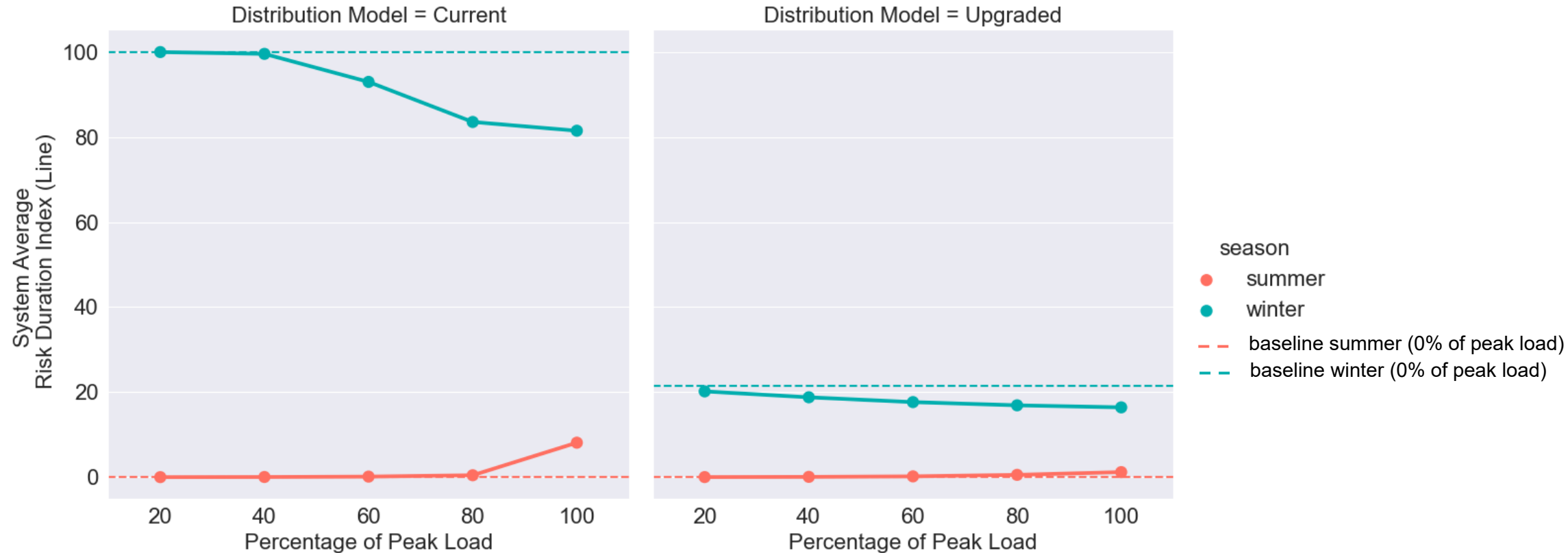
When breaking down our SARDI Aggregated, we see similar trends across each of the more specific SARDI metrics, generally decreasing risk in the winter, and increasing risk in the summer at high levels of adoption. For SARDI Transformer, we see only a small change when upgrading the feeder, given the relatively minor changes that were made to transformer sizes.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): SARDI Line

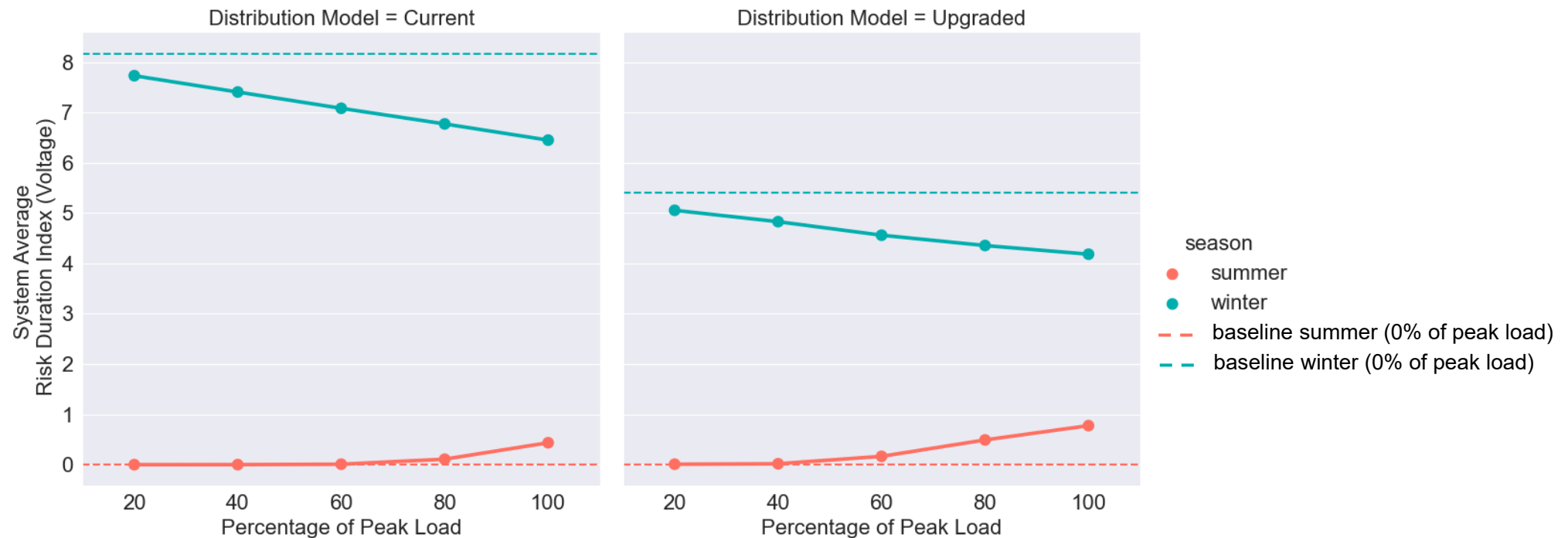
For SARDI Line, we see a much more substantial improvement when upgrading the feeder with larger conductors and a higher voltage class, though as with the previous solar-only scenario, there are remaining violations on the upgraded system.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): SARDI Voltage

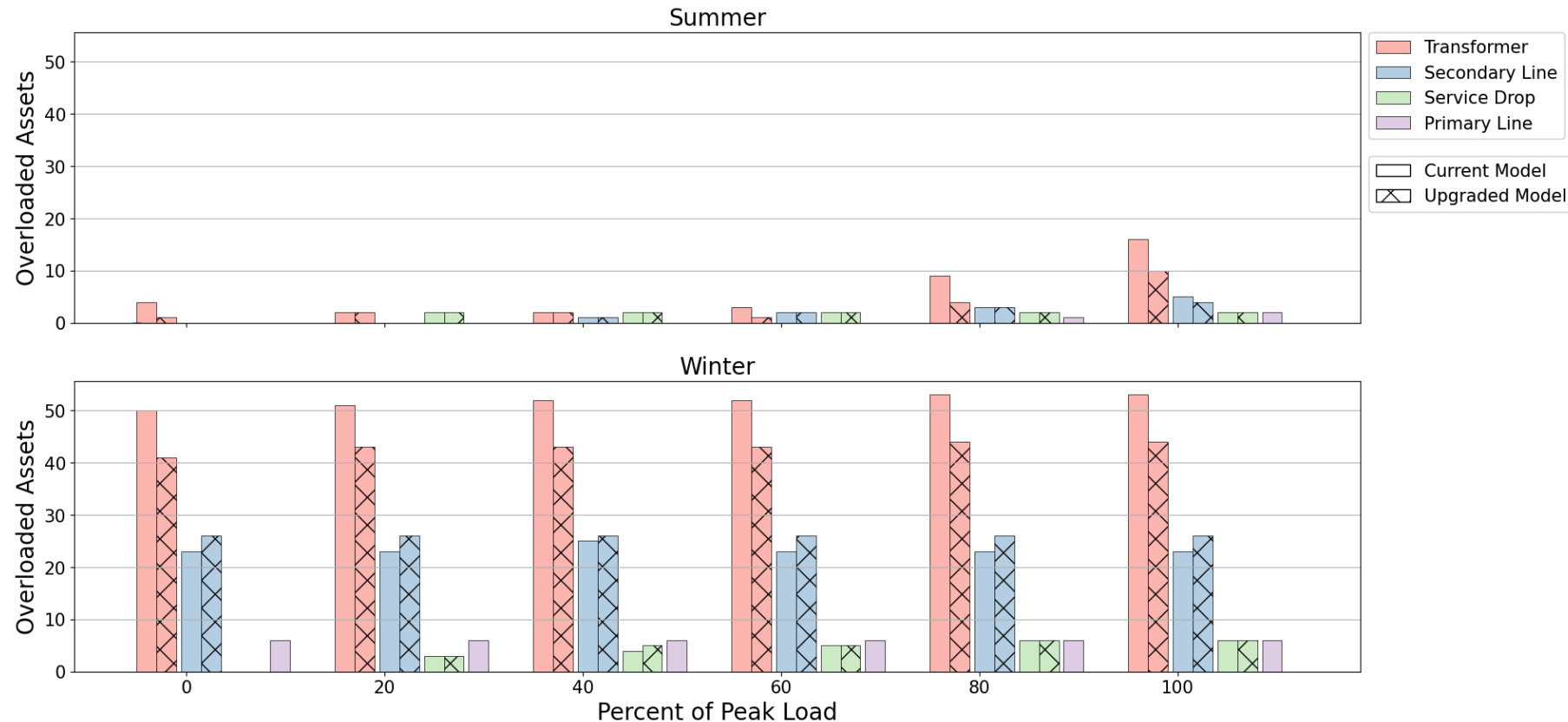
We see improvements in SARDI Voltage on the upgraded model, though some risks remain. A key distinction to be made here is that while the voltage violations in the wintertime are mostly *undervoltages* due to high loading and *improve* with additional distributed generation, the voltage violations in the summer are *overvoltages*, resultant from high amounts of solar export during periods of low load and *worsen* with additional generation. This is a great example of how distributed generation can both alleviate grid issues or cause them, depending on the pre-existing conditions that exist.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): Number of Overloaded Assets

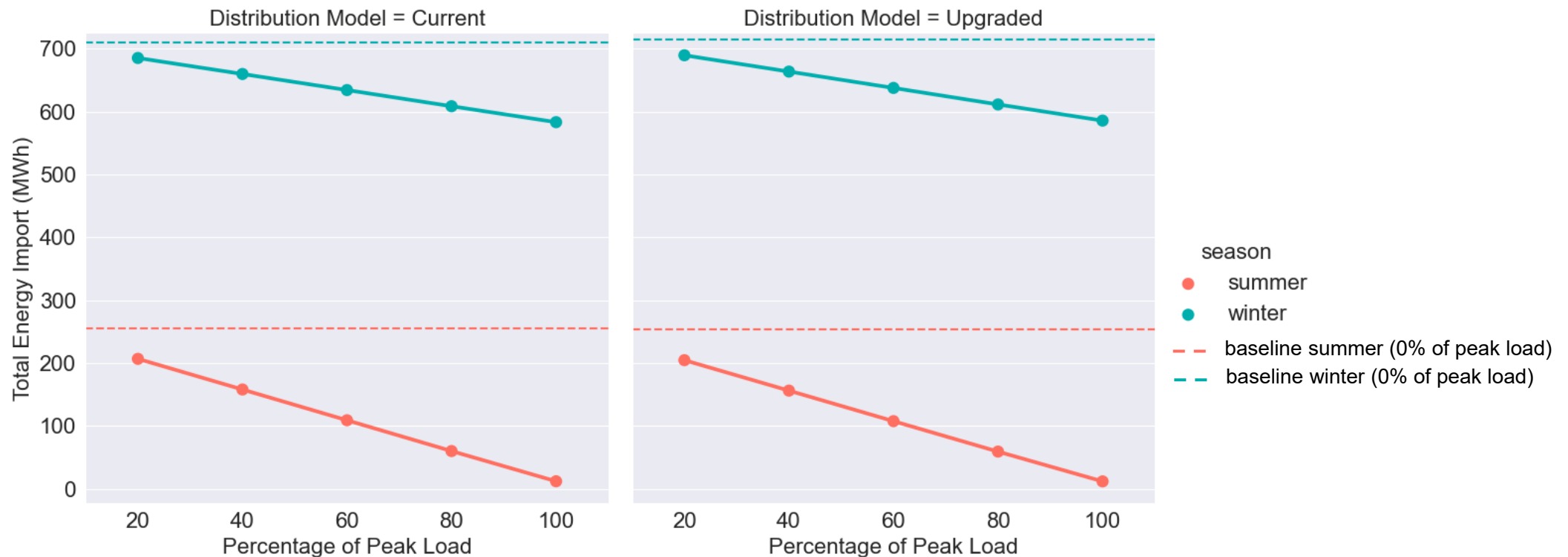
Adding energy storage to our solar-only scenario produces only small changes in the number of overloaded assets. We do begin to see a rise in overloads during the summer at high levels of DER adoption, due to the larger PV systems and increased export, as illustrated by our SARDI graphs on previous slides.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): Total Energy Import

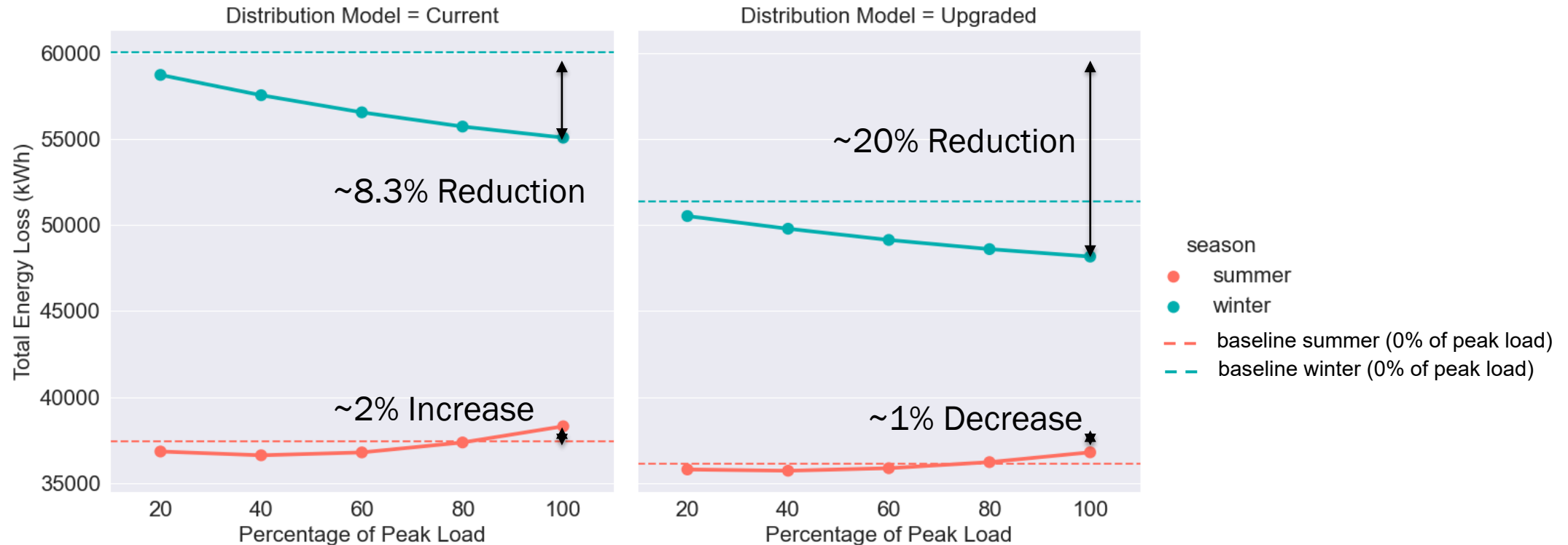
As we increase DER adoption we see energy import decline, so much so that in the summer, imports almost reach zero. While this does not mean no energy produced from bulk generation was consumed on this feeder, it means that the *net* consumption is almost zero. At times, the aggregate distributed generation on this feeder was likely exporting to the bulk system (i.e., reverse power flow at the substation) and at other times, energy was imported *from* the bulk power system.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar and Energy Storage (Future Electrification): System Losses

Overall, we see a larger reduction in losses in the winter, compared to our solar-only model, given the larger PV systems and ability to meet 100% of the peak load in installed solar capacity. We also see a net increase in losses at high adoption levels in the summer due to the higher solar export.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Key Takeaways

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- Adding battery storage allows for a larger cost-optimal rooftop solar installation at each house, alleviating the saturation effect we saw in the previous solar-only scenarios, and allowing for more significant improvements in system risk at higher levels of adoption.
- Improvements in system risk due to solar and storage adoption are seen in the wintertime, while high levels of solar adoption start to increase risk during the summertime, due to the increased export of distributed generation.
- Again, upgrading the system results in significant risk reduction, though issues in the form of overloaded secondary assets and transformers remain. Upgrading the system also reduces the negative impacts of high amounts of DER adoption seen in the summertime.
- Substantial loss reduction is seen in both models in the wintertime, though increases in losses are seen at high adoption rates in the summertime, resulting from increased export of distributed generation.
- The remaining risk levels in our upgraded model indicate the need for more robust secondary design standards.

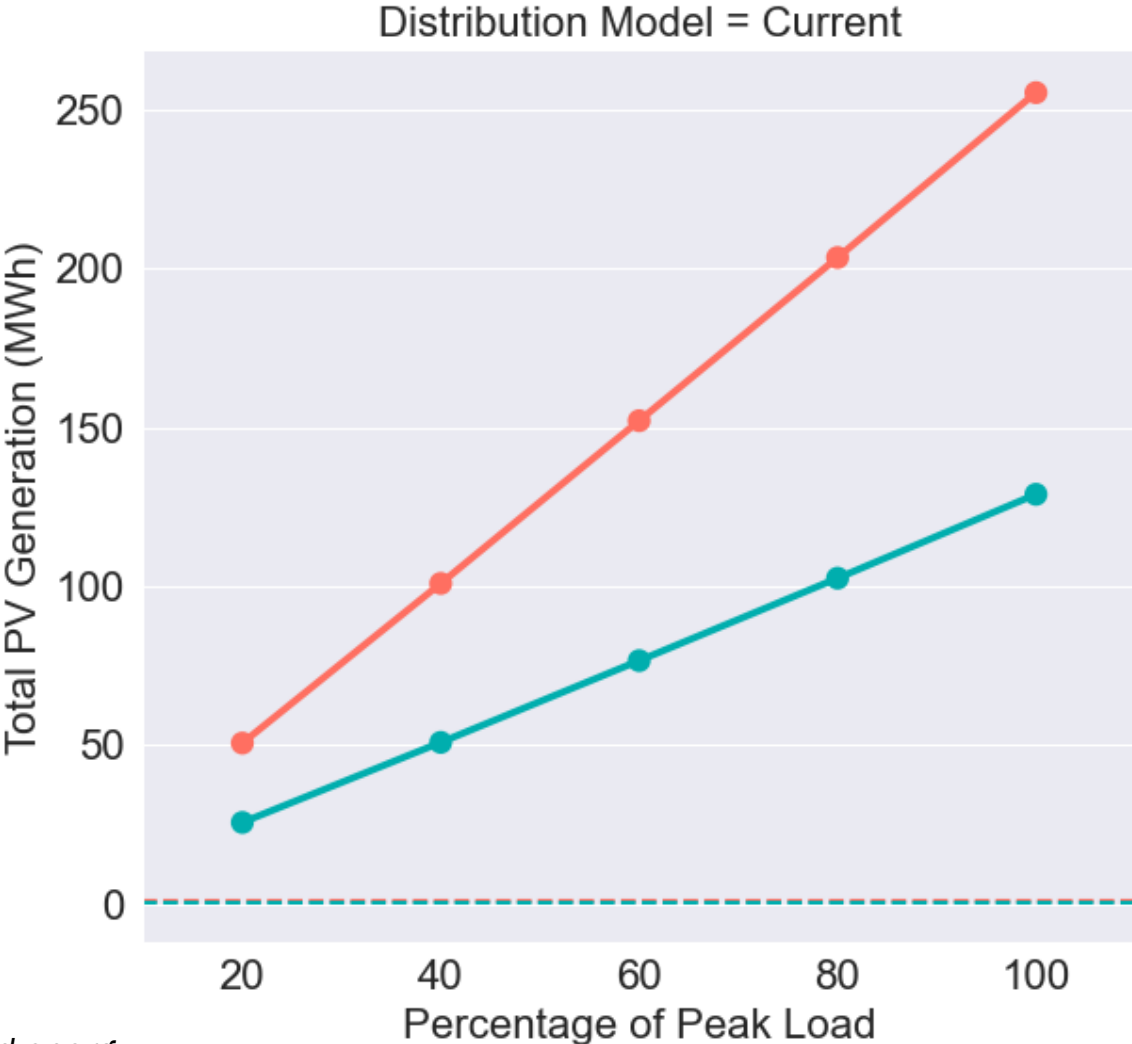
# **Rooftop Solar, Energy Storage and Electric Vehicles (Future Electrification): Grid Impacts**

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): Notes

The impacts of electric vehicles (EVs) largely depend on the time of day when customers charge. If charging lines up with solar generation, this has the potential to reduce grid impacts of both technologies, whereas if EV charging times line up with peak electric heating, this has the potential to exacerbate the grid issues of both technologies.

The following analysis assumes an 80%/20% split of level 1 (1.2 kW) and level 2 (7.6 kW) chargers, respectively. The difference in peak power demand between the two charger sizes is substantial. As a result, a high percentage of level 1 chargers only may not produce substantial additional risks when compared with building electrification. Alternatively, if a large number of level 2 chargers are installed, this would have a much more substantial impact, and may prove to be a larger concern than electric heating. At each adoption level plotted, EV chargers are installed at the same locations as those with solar and storage.

The addition of EVs does not change the algorithms or multipliers used to size solar or energy storage systems at these premises. As such, the solar generation plot to the right is identical to that of the solar + storage scenario prior.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): SARDI Aggregated

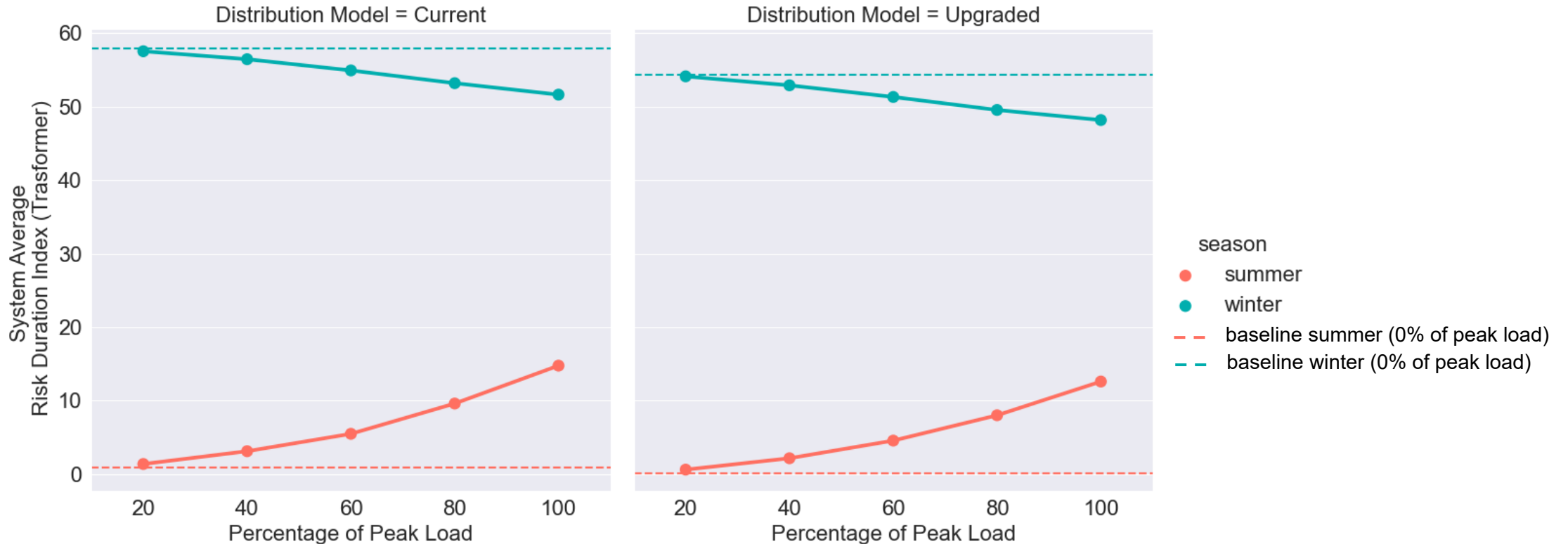
Adding the 80%/20% mix of level 1 and level 2 chargers results in almost no change in aggregated risk in the winter. This indicates that EV charging loads, as we have modeled them, for the most part, do not line up with peak heating hours and that over the modeled timeframe, building electrification presents greater risks. During the summer, we see a marked increase in risk, given the absence of any other electrification impacts. The persistent risks in our Upgraded Model indicate design standards which are not robust enough to accommodate high electrification or EV adoption, again almost exclusively on the secondary systems.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): SARDI Transformer

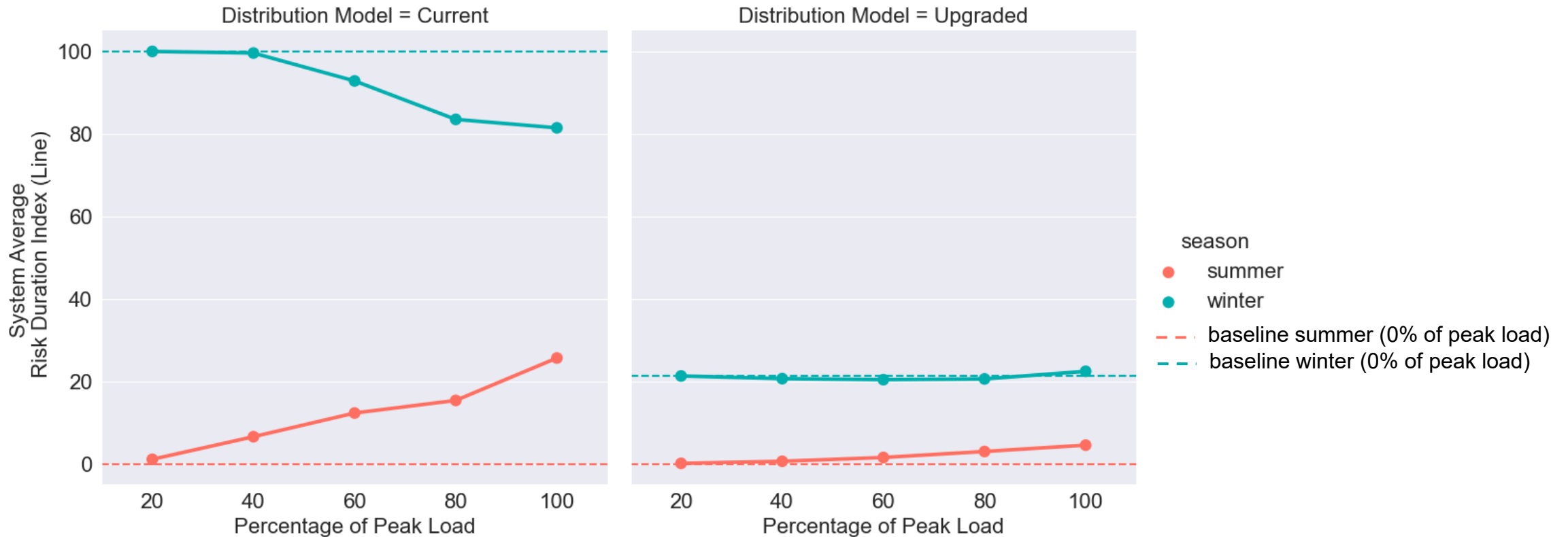
The winter trends largely mirror those in our solar-only and solar and energy storage scenarios, whereas in the summer we see a more substantial increase in risk to transformers with increasing adoption levels.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): SARDI Line

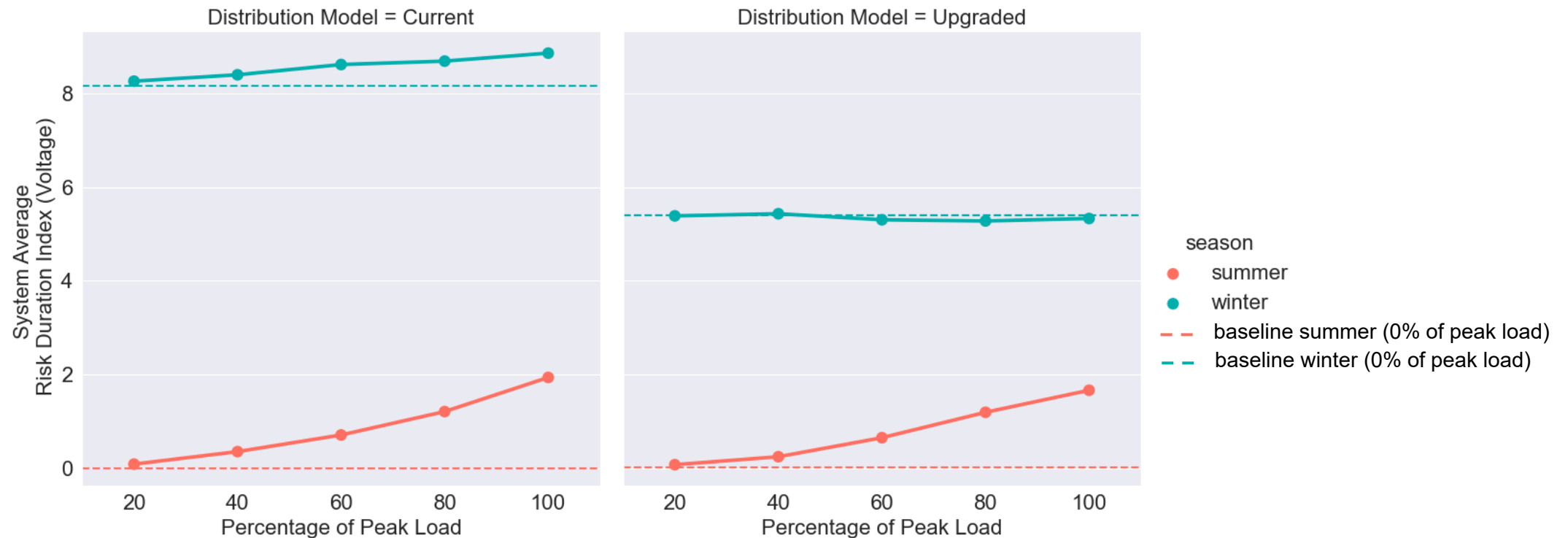
The SARDI Line metric for this scenario again looks very similar to those for the solar and energy storage scenario during the winter months, though there is slightly less of a risk improvement in our Upgraded Model. This indicates that at high levels of EV adoption, we start to see increases in risk that are not being mitigated by the presence of distributed generation and/or energy storage. Similar to the other SARDI metrics, we see an increase in risk from EV adoption in the summer across both the Current and Upgraded Models.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): SARDI Voltage

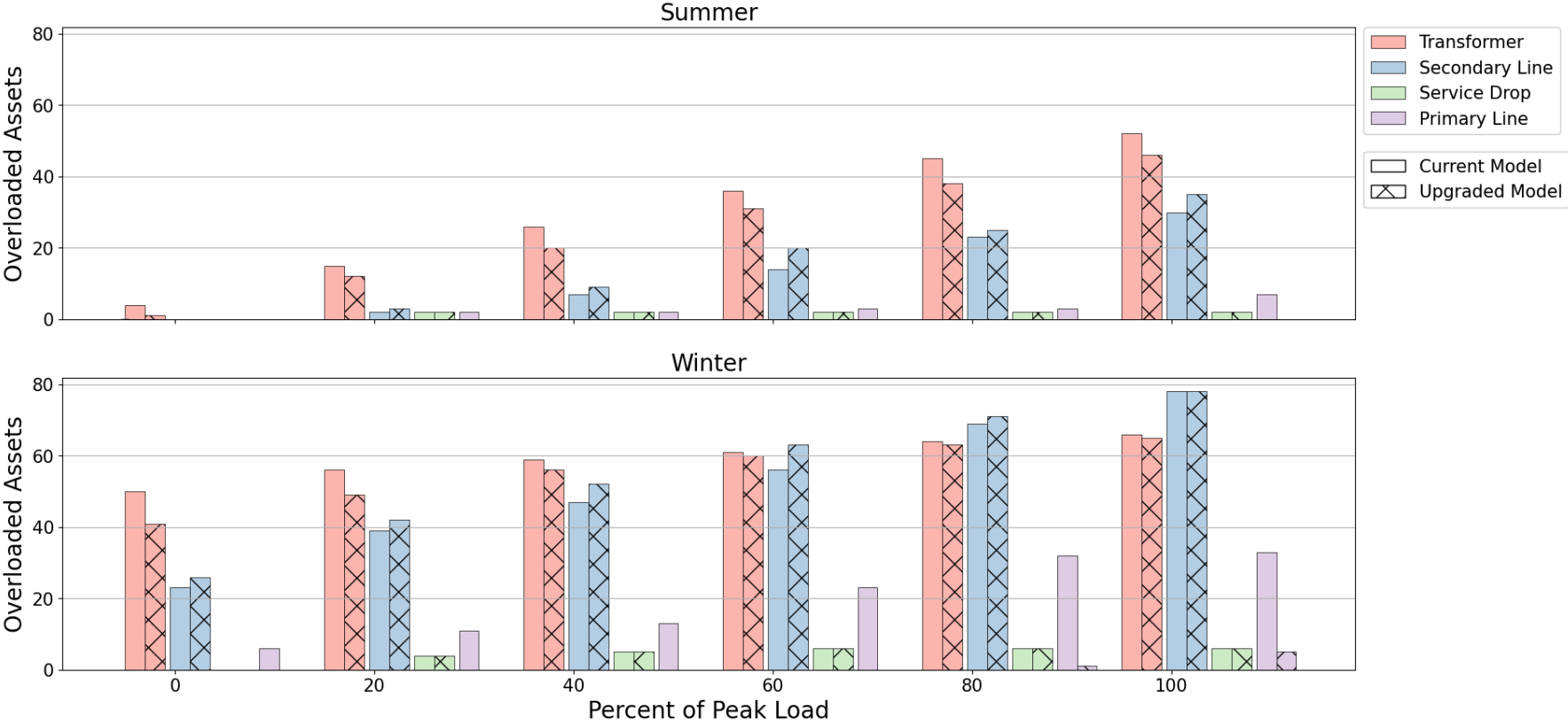
While our aggregated SARDI metric trends down in the winter, our SARDI *Voltage* trends *up* in our Current Model. Given that this is opposite to what we saw in our solar and energy storage scenario, this is likely a result of undervoltages occurring during charging hours. This may be a result of times when charging hours overlap with heating hours. The steeper increase in voltage violations in the summer, compared with the previous scenarios is indicative that there may be a combination of both overvoltages from solar export *and* undervoltages from EV charging loads.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): Number of Overloaded Assets

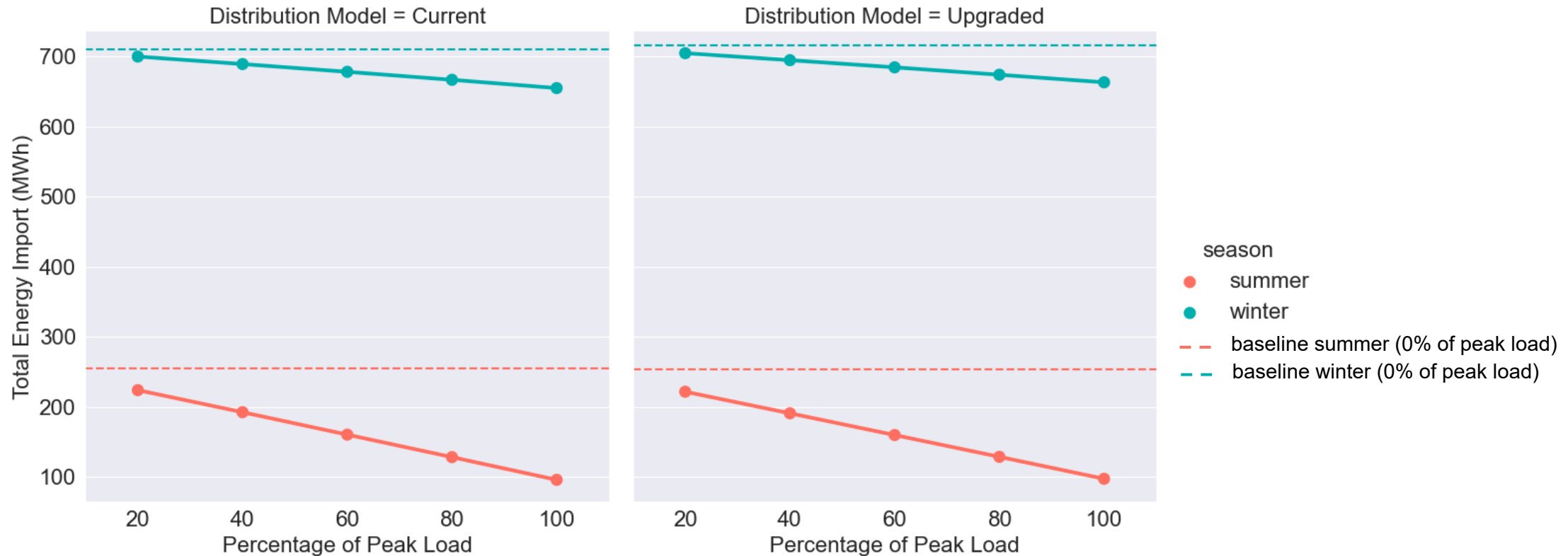
The results below show a substantial increase in the number of overloaded assets in both the summer and winter months compared with our solar + energy storage scenario.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): Total Energy Import

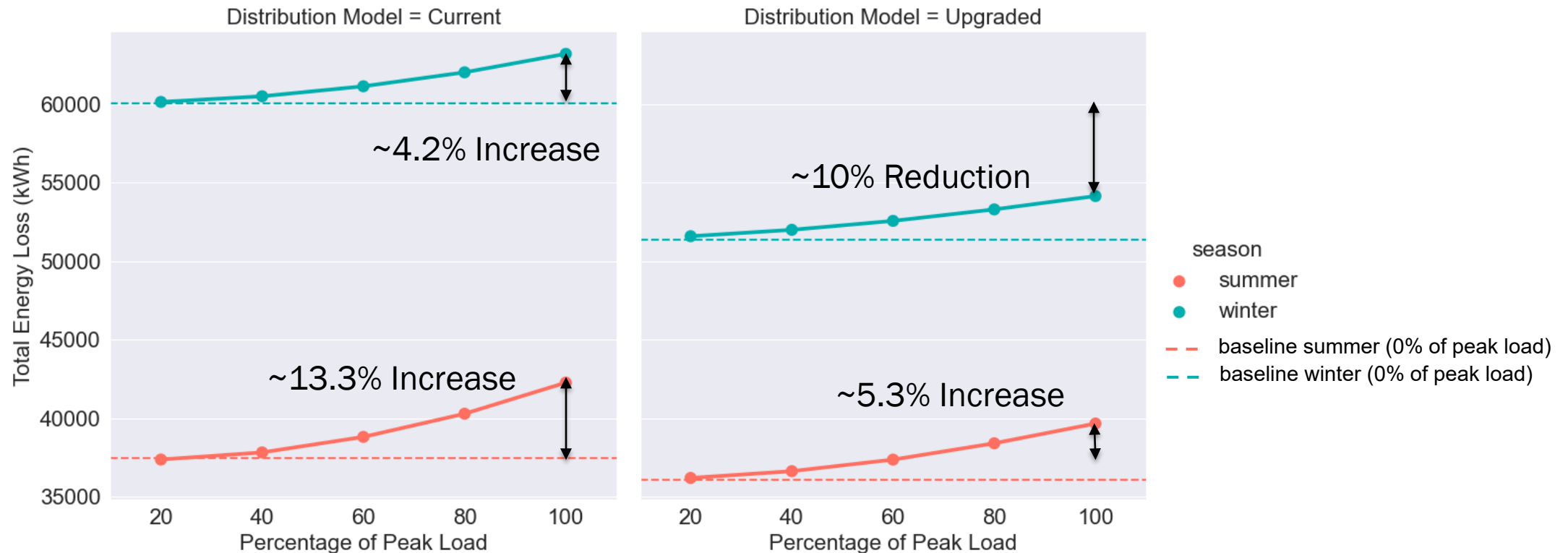
Compared with our previous scenario, we see a flatter, but still downward slope to our energy import. While added distributed generation decreases overall energy imports, this effect is partially offset by the added loads from increasing electric vehicle adoption at the same households.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Rooftop Solar, Energy Storage, and Electric Vehicles (Future Electrification): System Losses

Contrary to all other scenarios evaluated within this study, here we see an increase in losses, in both seasons, across both models as DER adoption increases. That said, we still see a net reduction in our wintertime Upgraded Model when compared to the baseline in our Current Model.



Percentage of Peak Load is defined as % of peak load before introducing distributed energy resources. The line plots shown take the average values across 25 simulation samples.

# Key Takeaways

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- Our modeled EV adoption assumes an 80%/20% split of level 1 and level 2 chargers, respectively. Level 1 chargers have a peak charging demand of 1.2 kW, while level 2 chargers can charge at a peak of 7.6 kW.
- EV charging patterns are modeled using NREL's EVOLVE tool, approximating customer behaviors and typical coincidence of charging demand across the region of Highland Park.
- The addition of EV chargers further exacerbates system risk, with notable increases in risk during the summertime at high adoption levels.
- The added demand from EV charging results in increased system losses. This increase is likely reduced, but not entirely offset, by the addition of distributed generation from rooftop solar.
- Our upgraded model shows less, but still significant levels of risk, indicating the need for revised design standards to accommodate the modeled levels of DER/EV adoption.

# Risk Metrics Summary Table

Analysis Scenarios *Battery sizing is based on 24-hour outage survival resilience objective	SARDI Aggregated (100% Average) (Summer/Winter)	SARDI Transformer (100% Average) (Summer/Winter)	SARDI Line (100% Average) (Summer/Winter)	SARDI Voltage (100% Average) (Summer/Winter)
Baseline Risk, Current Model, Base Electrification	0.64/0.54	0.64/0.54	0.00/0.00	0.00/0.00
Solar Only, Current Model, Base Electrification	0.42/0.51	0.41/0.50	0.01/0.01	0.00/0.00
Solar Battery, Current Model, Base Electrification	0.33/0.43	0.33/0.43	0.00/0.01	0.00/0.00
Baseline Risk, Upgraded Model, Base Electrification	0.02/0.00	0.00/0.00	0.00/0.00	0.02/0.00
Solar Only, Upgraded Model, Base Electrification	0.22/0.20	0.16/0.17	0.13/0.10	0.03/0.02
Solar Battery, Upgraded Model, Base Electrification	0.12/0.11	0.05/0.06	0.07/0.08	0.02/0.01
Baseline Risk, Current Model, Future Electrification	0.87/100.00	0.87/57.87	0.00/100.00	0.00/8.17
Solar Only, Current Model, Future Electrification	0.47/98.82	0.44/54.12	0.02/98.26	0.01/7.62
Solar Battery, Current Model, Future Electrification	10.17/83.16	4.67/46.82	8.11/81.50	0.44/6.45
Baseline Risk, Upgraded Model, Future Electrification	0.085/57.44	0.075/54.31	0.00/21.44	0.01/5.40
Solar Only, Upgraded Model, Future Electrification	0.23/53.20	0.18/50.53	0.14/19.35	0.04/4.98
Solar Battery, Upgraded Model, Future Electrification	4.24/45.48	3.14/43.05	1.18/16.42	0.78/4.18
Solar Battery EV, Current Model, Future Electrification	28.11/83.18	14.75/51.63	25.68/81.47	1.93/8.87
Solar Battery EV, Upgraded Model, Future Electrification	14.13/50.92	12.59/48.17	4.56/22.46	1.66/5.33

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# Estimate of Upgrade Costs

# Key Considerations for System Upgrade Costs

- A significant portion of DTE’s legacy 4.8 kV distribution system was built nearly a century ago and is in a state of severe decay today. Hardening such a system, while also bringing it up to current construction standards, would likely entail a nearly full rebuild of all distribution assets.
- Beyond the reconductoring, transformer replacements, and modifications to grid topologies represented in this study, some of the more significant cost adders associated with such an upgrade include a full substation rebuild, replacement of poles and crossarms, vegetation management, increasing the number and size of service transformers, implementing grid modernization technologies, and the labor.
- Further study is required to estimate the cost of system-wide upgrade needs specific to Highland Park. Components listed on slide 13 are the minimum upgrades necessary to study the impact of an upgraded 13.2 kV system but does not include costs for other necessary infrastructure.
- As part of a comprehensive rebuild, it would be advantageous to also incorporate modern grid technologies (e.g., SCADA, grid automation, modern system protection, etc.) to ensure superior reliability in the long run and contribute to wider grid modernization initiatives.
- For such a comprehensive upgrade as described above, DTE’s estimate is \$2.4–\$3.0 million per mile.<sup>1</sup>
- This project did not estimate the total length/size of DTE’s distribution system in Highland Park. This grid impact analysis only considered a portion of the Highland Park distribution network (see slide 10).

<sup>1</sup> Wang, Joy. “DTE Electric 4.8kV Technical Conference,” n.d. <https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference>.



# Thank You

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