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Impact of Electrification on Asset Life Degradation and Mitigation with DER

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SUMMARY

Distribution networks are currently faced with a plethora of changes in resources, equipment technology, structure, and loading. First, Distributed Energy Resources (DERs) have been increasingly penetrating distribution grids worldwide. DERs have been recognized as a Non-Wires Alternative (NWA) in certain use cases including peak shaving, renewable integration etc). The second imminent change in distribution networks is the electrification of loads, especially in the transportation and space heating sectors, driven at least in part by clean-air and sustainability goals. Electrification is expected to result in higher peak load levels as well as flatter daily and annual load shapes, due to the fact that it is primarily composed of off-peak and by storage-like loads like those of EVs, storage, and electric heating. Their valley-filling behavior results in distribution network apparatus being consistently loaded to high utilization levels.

As a result of these changes in load curve shape, distribution equipment may be subjected to increased operational stress compared to what it endured in the past, even if not loaded to higher net peak loads. For example, in the United States, the majority of distribution substation transformers typically warm up during the morning and afternoon as they approach demand peaks and then cool down afterwards as loading falls. Cumulative loss of life from this repetitive daily cycle is slow, so that expected service life of a typical unit is on the order of fifty years or more, even allowing for periods of intense overload during very rare contingencies. This has been the norm for the US electric utility industry in the last seventy years, but may no longer be the case in environments where electrification is more prevalent.

This paper explores whether these loading conditions, where cooling off is less substantial than at present due to electrification, is detrimental to the loss of life of distribution network assets. The paper begins with a fundamentals approach to developing an equation relating the transformer loss of life to its load curve utilization. In particular, the mathematical analysis is done using an exponential loss of life model, that relates loss of life to the internal temperature of the transformer. The evolution of the latter is based on a heat dissipation inspired equation and is affected by the internal temperature of the previous hours as well as the

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concurrent ambient temperatures and hourly power flow through the asset. The paper then takes the next step of calculating the value of a DER injection for lowering the flow through an asset. The DER injection valuation is calculated based on the avoided transformer replacement (or capital) costs.

In terms of results, the model is applied to a synthetic utility feeder, where the loss of life of the transformer at the feeder head is examined. We take N-1 conditions, N-1 loading practices (percent of overload and associated duration) and electrification into account. The results support the conclusion that (i) N-1 outages can have a significant impact on loss of life increase as a result of the exponential modeling of loss of life. Modest overloads are allowed by current utility practices for long periods of time, which can increase the impact on loss of life. Further, (ii) electrification-impacted loading results in less cooling potential for the transformer, which drastically decreases its life. Last but not least, (iii) DER injections can decrease transformer loading and alleviate some life loss. The first units of overload alleviated are more valuable in terms of transformer loss of life, due to the exponential nature of loss of life, therefore, the increased transformer life is not linear to the amount of DER injections.

KEYWORDS

Distributed Energy Resources, Asset Management, Transformer Loss of Life, Transformer Degradation, Marginal Cost, Locational Marginal Value, Non-Wires Alternative.

NOMENCLATURE

h, h_1 : clock hour
H: end of study horizon
L_0 : loss of life coefficient
$LL(h)$: loss of life at hour h
LL^{TOT}: cumulative loss of life at end of study horizon, H
T_0 : design ambient temperature, under which loss of life is negligible
$T(h)$: transformer internal temperature at hour h
$T_{amb}(h)$: ambient temperature at hour h in degrees Celsius
M: coefficient used in heat dissipation component of transformer temperature evolution equation
c: coefficient used in hourly temperature difference component of transformer temperature evolution equation
$I(h)$: current magnitude at hour h
R: resistance of transformer (in per unit)
α: inflation rate
NPV: function calculating Net Present Value, taking into account inflation rate α, number of years in study horizon H and the annual values.

TRANSFORMER LOSS OF LIFE EQUATIONS

The loss of life of a transformer is affected by the transformer's internal temperature. We assume that each clock hour results in the degradation of the life of the transformer by an amount larger or smaller than the clock time elapsed, based on the internal temperature of that clock hour. We express this as an exponential function using [3, 4]:

$$LL(h) = L_0 \exp(k(T(h) - T_0)$$

Where T_0 is a design ambient temperature, under which loss of life is negligible. At the end of the horizon, namely H, the cumulative loss life is:

$$LL^{TOT} = \sum_{h=1}^{H} LL(h) = L_0 \sum_{h=1}^{H} \exp(k(T(h) - T_0)$$

A typical value for the design ambient is $T_0 = 20°C$. The internal temperature at each clock hour, h, is itself affected by (*i*) the internal temperature during the previous clock hour, (*ii*) the power flow through the transformer at this clock hour, and (*iii*) the ambient temperature at this clock hour. These are reflected in a linear way as follows [2, 6, 7]:

$$T(h) = T(h-1) + \frac{1}{M}[I^2(h)R - c\big(T(h) - T_{amb}(h)\big)]$$

, or equivalently

$$T(h) = \frac{M}{M+c}T(h-1) + \frac{1}{M+c}I^2(h)R + \frac{c}{M+c}T_{amb}(h)$$

A DER injection at a distribution node will impact the internal temperature and, in turn, the hourly and total loss of life, through lowering the flow on the transformer, represented by the current magnitude. As a result, the sensitivity of the internal temperature of clock hour h to a marginal current change at hour h_1 is:

$$\frac{\partial T(h)}{\partial I(h_1)} = \frac{M}{M+c}\frac{\partial T(h-1)}{\partial I(h_1)} + \frac{2R}{M+c}I(h)\frac{\partial I(h)}{\partial I(h_1)}$$

We note that $\frac{\partial I(h)}{\partial I(h_1)} = \begin{cases} 0, h \neq h_1 \\ 1, h = h_1 \end{cases}$, therefore the above equation can be rewritten as:

$$\frac{\partial T(h)}{\partial I(h_1)} = \begin{cases} 0, h_1 \geq h-1 \\ \left(\frac{M}{M+c}\right)^{h-h_1} \frac{2R}{M+c} I(h_1), h_1 < h \end{cases}$$

The interpretation of the equation above is that a DER injection at any point in time cannot change the internal temperature of past hours, but it impacts all of the future hours, with a diminishing impact (expressed through the ratio raised to the power of elapsed time since the injection) as time goes by.

This sensitivity of the internal temperature is used to determine the sensitivity of the hourly and total loss of life as follows:

$$\frac{\partial LL(h)}{\partial I(h_1)} = kL_0 \exp(k(T(h) - T_0)) \frac{\partial T(h)}{\partial I(h_1)} = kLL(h)\frac{\partial T(h)}{\partial I(h_1)} =$$

$$= \begin{cases} 0, h_1 \geq h-1 \\ kLL(h)\left(\frac{M}{M+c}\right)^{h-h_1} \frac{2R}{M+c} I(h_1), h_1 < h \end{cases}$$

$$\frac{\partial LL^{TOT}}{\partial I(h_1)} = \sum_{h=1}^{H} \frac{\partial LL(h)}{\partial I(h_1)} = \frac{2kR}{M+c} I(h_1) \sum_{h=1}^{H} LL(h)\left(\frac{M}{M+c}\right)^{h-h_1}$$

For the financial calculations, we allocate the transformer replacement (capital) cost to an hourly cost, based on the transformers lifetime as reported by the manufacturer. Then the valuation of a DER injection in \$/MWh and \$/MVarh is the Net Present Value (NPV) of the hours of transformer life saved by the DER injection times the hourly transformer cost, over the total DER injection kW.

$$\pi_b^P = \frac{1}{\sum_{h_1} P_b(h_1)} NPV\left(\frac{TF_{cost}}{TF_{lifetime}} \sum_{h_1} \frac{\partial LL^{TOT}}{\partial I(h_1)} \frac{\partial I(h_1)}{\partial P_b(h_1)} P_b(h_1), H, \alpha\right)$$

$$\pi_b^Q = \frac{1}{\sum_{h_1} Q_b(h_1)} NPV\left(\frac{TF_{cost}}{TF_{lifetime}} \sum_{h_1} \frac{\partial LL^{TOT}}{\partial I(h_1)} \frac{\partial I(h_1)}{\partial Q_b(h_1)} Q_b(h_1), H, \alpha\right)$$

Where α is the inflation rate.

RESULTS USING LOADING BEFORE ELECTRIFICATION

The analysis above is applied to a realistic transformer loading curve. A 50-year horizon is assumed. Results below show the internal temperature and loss of life evolution for two years in the horizon: one where no N-1 outages occur and one where a single N-1 outage occurs. For both cases, the yearly loading levels represent a summer loading feeder and are realistic in the sense that the maximum loading levels, assumed to correspond to an N-1 outage, are consistent with normal utility practices of loading levels and the corresponding duration. In particular, we assume that during the outage the loading of the transformer can be as high as 130% for about 10 days. A loading higher than 170% can only be accommodated for 2 hours, after which the load must be switched if the outage is not fixed. Ambient temperatures have been obtained through NREL's PVwatts tool for the Chicago area [1].

First, we show results on a typical summer peaking feeder with an expected curve for today, with and without N-1 outages. Then, we assume the results of electrification on this feeder and repeat the analysis.

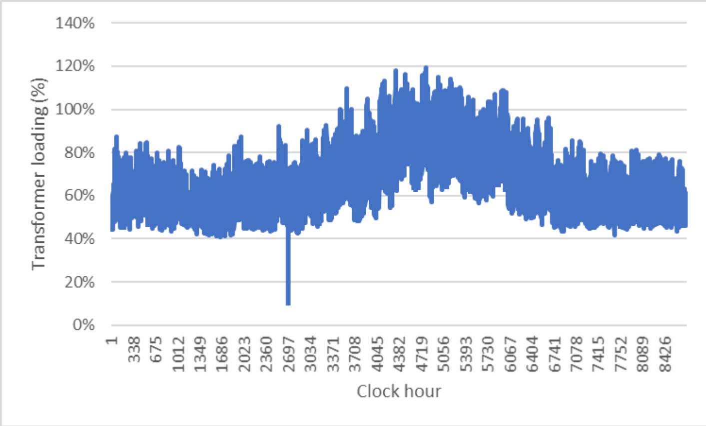

Figure 1. Transformer loading during years without N-1 outages.

The internal temperature developing inside the transformer apparatus because of the above loading profile is outlined in the following graph.

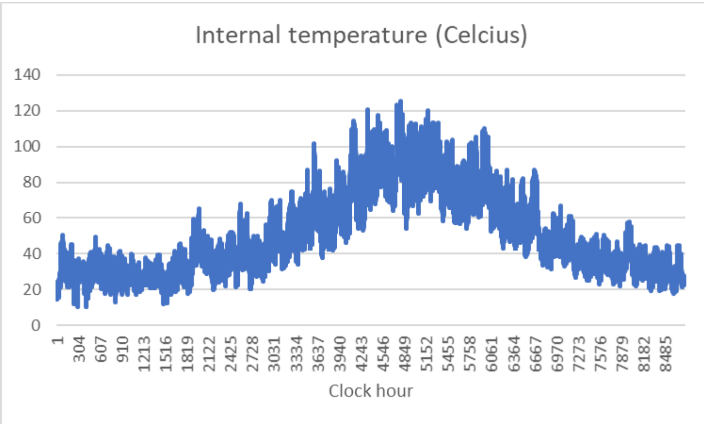

Figure 2. Transformer's internal temperature during years without N-1 outages.

The loss of life of the transformer is depicted in the figure below. At the end of the calendar year, 8760 hours of clock life have elapsed and the transformer has lost about 1830 hours of its lifetime. For an assumed manufacturer's lifecycle of 150,000 hours, the transformer would last for 82 years (assuming same loading every year).

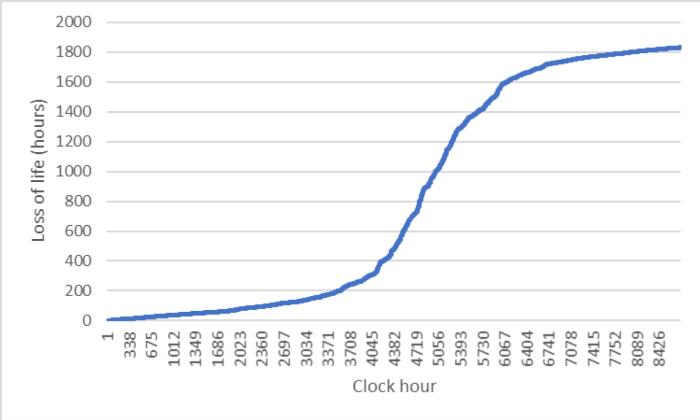

Figure 3. Cumulative loss of life of transformer during years without N-1 outages.

The following three graphs show the loading, internal temperature and cumulative loss of life during the years when an N-1 outage occurs. Loss of life after a calendar year (8760 hours) increases to 2057 hours, i.e. a 12.4% loss of life increase.

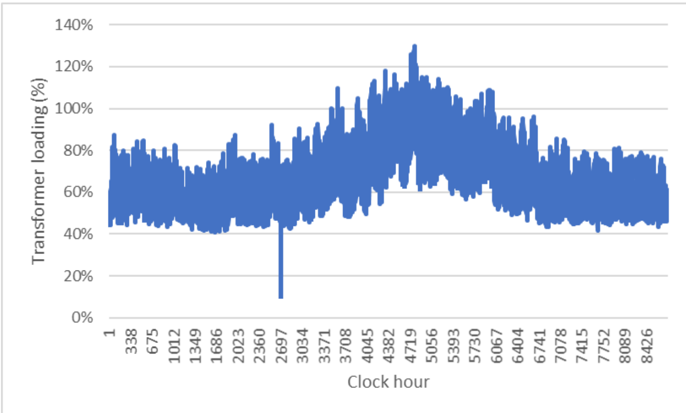

Figure 4. Transformer loading during years with an N-1 outage.

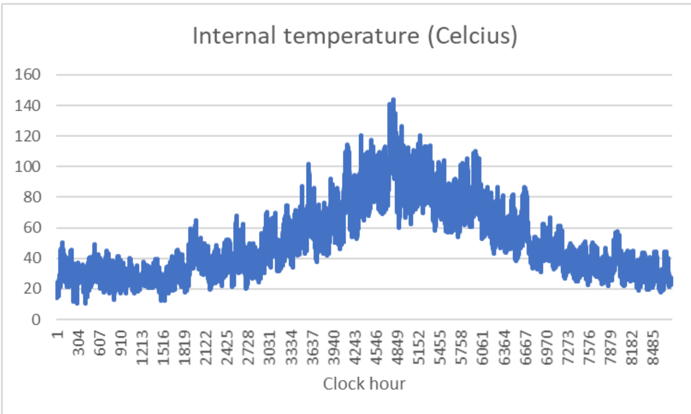

Figure 5. Transformer's internal temperature during years with an N-1 outage.

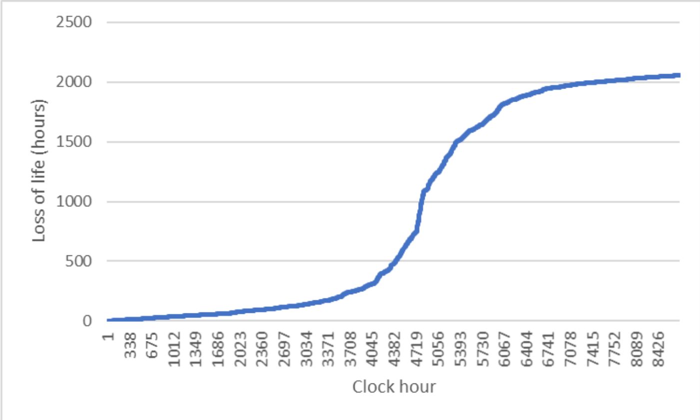

Figure 6. Cumulative loss of life of transformer during years with an N-1 outage.

Assuming that an N-1 outage happens once every 5 years, and that every year without N-1 outage is similar to the initial results above, at the end of the 50 calendar year horizon, the transformer would have lost 62.5% of its total life. In other words, with the assumed 5-year frequency of the N-1 outage, the transformer would live to approximately 80 years.

Note that an extreme outage that would increase the loading to 170% can be sustained for 2 hours only for reliability reasons. As such, this does not have a significant impact on the transformer loss of life. For the assumptions made above, the loss of life after one calendar year would increase by 2.24% only, compared to an N-0 only year.

Assuming a DER injection at the transformer end, occuring at the peak loading hour and with a 10 hour duration, would result in the following loss of equipment life improvement.

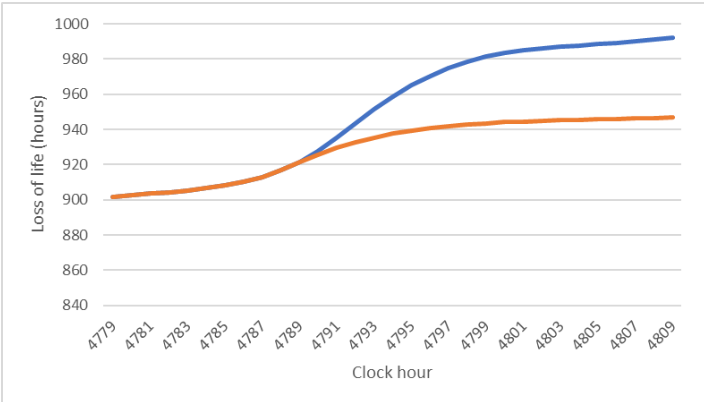

Figure 7. Comparison of loss of life evolution before and after DER injection, case of N-1 outage, hours 4780-4810, injection hours 4790-4800.

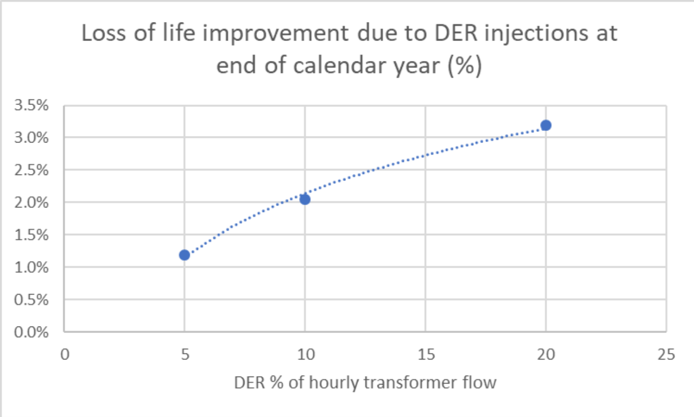

Figure 8. Percent improvement of loss of life at end of calendar year, case of N-1 outages, due to DER injections for different levels of DER injections.

As per the above figure, the improvement as the DER injections increase is slower than linear. The interpretation of this logarithmic behavior is that shaving the peak of the load results in significant improvement. Due to the exponential nature of the loss of life, further decreasing the loading, is not as impactful.

Assuming that an N-1 outage happens once every 5 years, and that every year without N-1 outage is similar to the initial results above, then for the 50 calendar year horizon, the NPV of a 5% DER injection for 10 hours is $5,328, while the NPV of a 20% DER injection for 10 hours is $14,675 (2% inflation rate used, assumed transformer cost of $2M) [5].

RESULTS USING POST-ELECTRIFICATION LOADING

First, we use real utility data for a feeder of interest to edit the loading curve and reflect the impacts of electrification. The increase in the peak demand for each type of load (between residential, commercial, industrial and transportation) is forecasted. Then, allocating feeder loads to each of these four categories, allows for the calculation of the increased peak flow through the substation transformer using percentage of load allocation. Figure 9 and Table 1 below report on these values for the distribution feeder of interest.

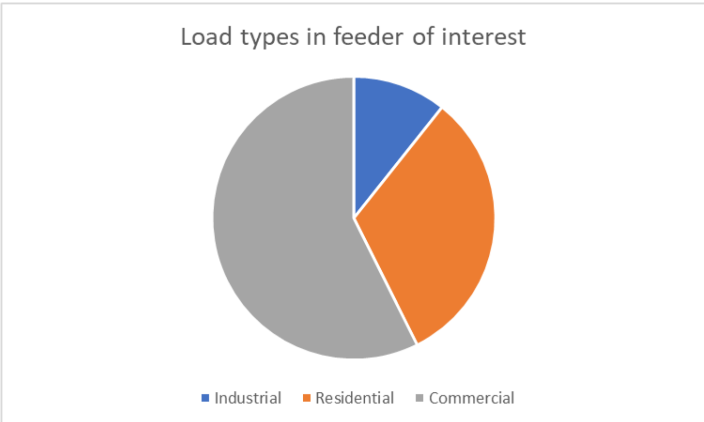

Figure 9. Load types (%) of feeder that is impacted by electrification.

Table 1. Increase of annual peak demand due to electrification, as % of transformer rating, per load type.

Industrial	0.1%
Residential	9.0%
Commercial	1.9%

Transportation	1.9%

Therefore, the annual peak is increased by 5.9%. Further, the off-peak hours are shifted such that the difference between the daily peak and the corresponding off-peak hours of that same day is halved. The first and second figure below show the internal transformer temperature and the loss of life for a calendar year, respectively. The third figure contrasts the loss of life before and after a 20% DER injection, zooming in closer to the hours of DER injections (i.e. close to demand peak). The fourth figure graphs the loss of life improvement due varying levels of DER injections for 10 hours close to the peak.

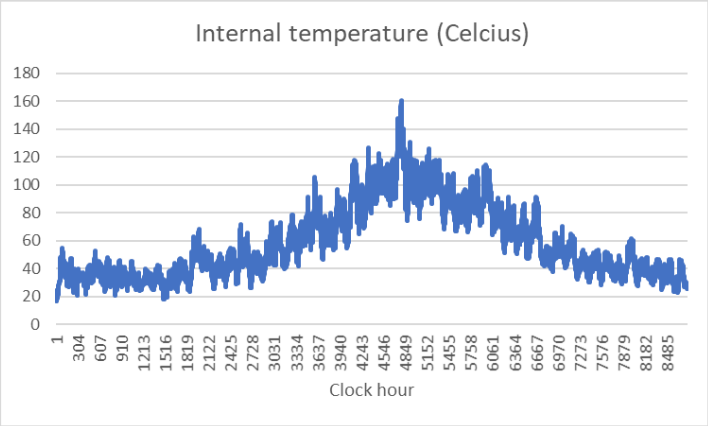

Figure 10. Transformer's internal temperature with electrification-impacted loading.

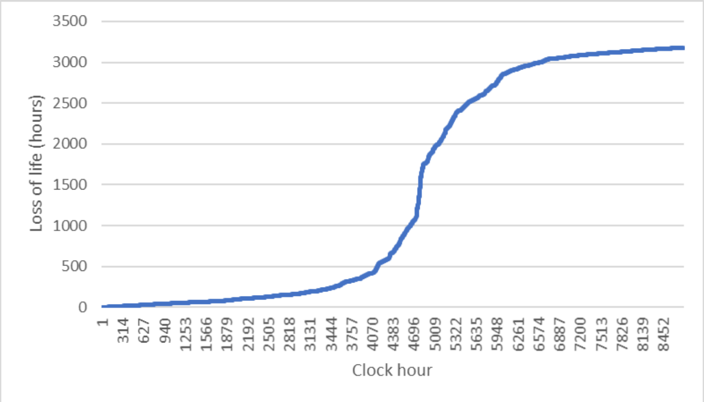

Figure 11. Cumulative loss of life of transformer with electrification-impacted loading.

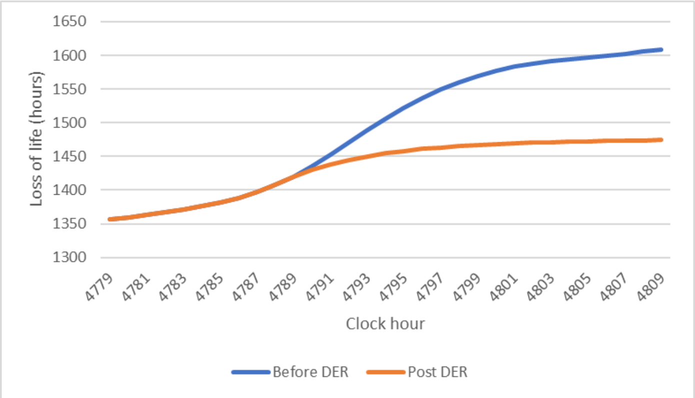

Figure 12. Comparison of loss of life evolution before and after DER injection, case of electrification, hours 4780-4810, injection hours 4790-4800.

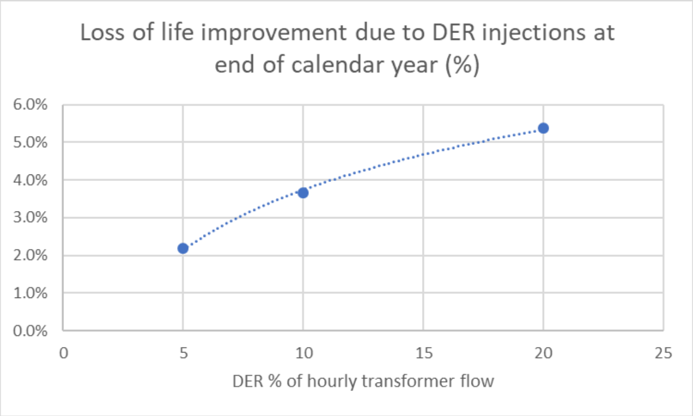

Figure 13. Percent improvement of loss of life at end of calendar year, case of electrification, due to DER injections for different levels of DER injections.

The loss of life change is dramatic compared to the fact that the overall peak increased by 5.9% only. This result showcases the significance of off-peak hours for transformer cooling in its loss of life.

For the 50 calendar year horizon, the NPV of a 5% DER injection for 10 hours is $14,061, while the NPV of a 20% DER injection for 10 hours is $35,773 (2% inflation rate used). These constitute a 143%-163% increase in NPV of DER injection compared to the pre-electrification case.

CONCLUSIONS

The exponential nature of the loss of equipment life means that an increased loading, as is the case in an N-1 outage, results in a significant increase in loss of equipment life. The change to the internal temperature and loss of equipment life start at the beginning of the N-1 outage, and continue for longer than the duration of the outage. This is due to the fact that the internal temperature of a specific hour is dependent on the internal temperature of previous hours (see equations above).

Further, a short burst of extremely high loading that is sustained for a short amount of time is less detrimental to the loss of equipment life of the transformer than a lower loading (that still exceeds transfromer nameplate rating) for a longer period of time. This is supporting the claim that the loss of life of a transformer is severely impacted by an electrification-affected load shape.

The application of an electrification-like loading curve to a transformer sheds light to the significance of the off-peak hours. As can be seen above, the transformer does not cool down as much since the gap between on-peak and off-peak hours is narrower in an electrification environment. Therefore, the loss of equipment life is heavily increased.

The impact of a DER injection to loss of equipment life is non-linear. While the DER indeed impact the transformer loading in a linear fashion (with few assumptions), the loading impacts the loss of life exponentially. Therefore, the conclusion is that using less DER to shave the very top of the peak is more impactful than procuring higher DER injections to lower the flow on overloaded elements even further. This is the case even when the lesser DER injection still leaves the flow on the transformer over its nameplate rating.

Current utility design and operations practices may not be well suited where temperatures are higher and load profiles are flatter. Given the relatively long equipment life of assets such as transformers and their high value, this is an important issue. More in depth analyses can indicate how transformer sizing, rating, and operations practices can be adjusted to anticipate these changes and mitigate the adverse effects.

As a concluding remark, we note that one goal of the Non-Wires Alternative initiative is to increase asset utilization ; that is, an alternative for building capacity. While laudable, this has the unintended consequence of levelizing loading and reducing the amount and time that lower loading levels will exist to provide for asset cooling. This effect can be exacerbated by changed temperature profiles associated with climate change which are expected to increase night time temperatures in some regions. Electrification, increased nighttime temperatures, and urban heat island effects could combine to intensify this effect with adverse impacts. This paper does not purport to explore all of these effects in detail. Rather, it illustrates some key aspects and lays out a methodology for exploring them further.

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