Comparing T&D Capacity Options, Including Stationary and Transportable DERs, On a Risk Adjusted Cost Basis

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Background and Approach
The theme of this paper is the use of risk-adjusted-cost to compare electric T&D capacity options, including modular distributed energy resources (DERs). Risk adjusted cost has two components: 1) “direct cost” – cost to own equipment, rent or lease payments, or even payments made for load management and 2) financial risk. A general definition of financial risk is financial exposure whose magnitude is not certain. As described below, there is risk associated with all options that might be used as marginal T&D capacity.

Options evaluated include: 1) do nothing, 2) add capacity to (upgrade) the existing capacity, 3) generic distributed energy resources (DERs), and 4) Diesel genset rentals. Generic DERs have “perfect” reliability – consistent with the definition of “physical assurance” used in California. [1] They could be generators, storage devices, or load control. Two DER option types evaluated are Diesel genset rentals operated 200 hours/year. The first rental option is one 500 kW unit. The second rental option is a 500 kW unit plus a 250 kW unit. Rental charges are based on prevailing rates in California. [2]

An important premise for this work is that understanding the sources and magnitude of risk allows for superior investing by: 1) avoiding some sources of risk, and 2) prudent responses to others. For utilities, the result would be a portfolio approach to T&D investing with lower overall cost (of service) borne by utility ratepayers while investors receive authorized returns.

The approach used is designed to be auditable and is intended to realistic, though as simple as possible. It has four primary elements: 1) uncertainty, 2) cost, 3) case, and 4) risk. Key sources of uncertainty are characterized, including related probabilities. For example, probabilities are assigned to a range of possible peak demand growth levels. Costing addresses financial and cost criteria such as total and annual upgrade costs. The case is the specific situation -- location, circuit, year, etc. -- being evaluated. Risk is estimated for each option, based on case-specific uncertainty and costs. Risk is calculated as the sum of probability-weighted values using a basic probability-tree framework. Adding risk to annual direct cost yields the single-year risk adjusted cost.

It is important for readers to note that, to one extent or another, utility T&D planners do address uncertainty and risk. But, often that involves 1) a significant amount of engineering judgment and art and/or 2) T&D design based on targets or standards such as minimum levels of electric service reliability (e.g. the SAIDI and SAIFI indices). [3]

Key Elements of Uncertainty and Risk Evaluated
Four key uncertainties evaluated were: 1) inherent load growth, 2) block load additions, 3) weather, and 4) utility construction delays. Inherent load growth is driven mostly by economic conditions. Timing and, to a lesser extent, the likelihood of block load additions (or reductions) may be uncertain. Extreme weather and upgrade construction delays -- that may lead to T&D equipment overloading -- are always a possibility. DER reliability-related uncertainty is addressed deterministically.

Most risk is related to cost that could be incurred due to T&D equipment overloading if a specific option is used. Elements of that cost include: 1) T&D equipment damage (damage) expressed in terms of the value of lost life, 2) utility lost revenue during outages (lost revenue), 3) utility labor for responding to interruptions (response cost), and 4) customer cost for “unserved energy” during outages. Unless a DER is sized based on the worst case, the risk associated with DER undersizing must be included in the evaluation.

1 This project is part of the collaboration between the California Energy Commission (CEC) and the Energy Storage Systems Program of the U.S. Department of Energy (DOE/ESS) through Sandia National Laboratories (SNL).
**Assumptions – Load and Cost**

The case evaluated was characterized by the following key assumptions: A 12,000 kW T&D node will be upgraded to 16,000 kW (+4,000 kW). Peak load in the year before the upgrade -- 11,700 kW -- was projected to increase to 12,150 kW in the next year. Inherent load growth uncertainty is as follows: 100 kW, 20% chance; 200 kW 60% probability; and 300 kW, 20% chance. Block loads uncertainty is the following: 0 kW added, 15% chance; 250 kW, 50% probability; and 500 kW added, 35% chance. T&D design load is estimated using the one-year-in ten maximum of 110°F ambient with the following uncertainty: 7.5% chance of 113°F and 2.5% chance for 116°F. Temperature related effects include: a) increased load, primarily for air conditioning and b) T&D equipment derating for high ambient temperatures (temperatures above the design temperature). No appreciable damage is assumed to occur for overloading below a 4% “floor” and overloading exceeding 11% is assumed to result in outages whose duration lasts from a few minutes to five hours (as a function of ambient temperature and overload magnitude).

Given the three probabilities for the three uncertainties, there are 27 possible future outcomes. Each of these 27 scenarios is an end-state in the probability tree.

T&D upgrade cost assumed was $260/kW added \([4]\) for a total cost of $1,040,000 and an annualized cost of $114,000 (using .11 fixed charge rate). Damage was estimated assuming twelve years of useful life for the 12,000 kW existing equipment whose replacement cost is $30/kW (salvage value = 396,000 or $39,600/year). On-peak energy price – used to calculate utility lost revenue – is assumed to be 14¢/kWh. The cost for the utility to respond to outages was assumed to be a flat $1,000 per event. A conservative value of $3/kWh was assumed for “unserved” energy demand. For the case evaluated, there is a 15% chance of construction delay; the risk is calculated as 15% of the do nothing option risk.

**Results**

The results below must be construed within this context: key facets of the evaluation require further validation and development, especially: 1) duration and frequency of outage events related to overloading, and 2) cost for those events (damage, response, and cost for unserved energy).

Results are shown in Figures 1 through 5. Figure 1 shows the magnitude of single year cost that would be incurred, for each of 27 scenarios evaluated. Values shown reflect gross annual cost associated with possible levels of overloading, without regard to the likelihood that a given level of overloading will occur. The three distinct clusters reflect costs incurred at the three discrete ambient temperature levels used for the evaluation.

![Figure 1. Gross Annual Cost Associated with all 27 Scenarios for the Do Nothing Option.](image-url)
multiplying the scenario-specific gross cost (shown in figure 1) by the respective probability of occurrence (shown on the y axis in figure 2). The expected value of risk for the do nothing option is the sum of those 27 probability-weighted values, or about $118,000 for one year.

![Graph showing probability of occurrence vs. overloading](image)

**Figure 2. Do Nothing Option - Likelihood that a Specific Level of Overloading will Occur**

The elements of risk and total risk for the six options evaluated are shown in Figure 3.

![Bar chart showing risk associated with six possible T&D capacity options](image)

**Figure 3. Risk Associated with Six Possible T&D Capacity Options**

Figure 4 shows how risk declines as DER capacity (in lieu of an upgrade) increases. Also shown in Figure 3, the risk associated with no DER is equal to the risk for the do nothing option. A companion to Figure 4 is figure 5 which shows the total cost for DERs as a function of annual cost per kW per year ($/kW-year) and of DER capacity (kW).
When combining values in Figures 4 and 5 with the risk-adjusted cost for the do nothing option and the risk and direct cost for the upgrade option, the results are shown in Figure 6. As shown, the upgrade has the highest risk adjusted cost. If a perfect DER costing $75/kW-year is available then the optimal solution (on a risk adjusted cost basis) is to install about 750 kW of DER. If DER costs $100/kW-year then the optimal DER capacity is about 600 kW. DER costing $150/kW-year.

![Figure 4. Risk Associated with Various Levels of DER Capacity](image1)

![Figure 5. DER Direct Cost](image2)
Criteria that can affect results significantly include: 1) load growth uncertainty, especially regarding block loads, 2) number and duration of outages due to overloading, 3) cost for customers’ unserved energy demand, 4) existing equipment: capacity “headroom” remaining, useful life remaining and replacement cost, and 5) uncertainty about construction delays.

Conclusions
Based on results from the evaluation authors conclude that:

1) Under typical conditions the do nothing option provides notable competition for DERs.

2) DERs costing about $100/kW-year -- net of any additional benefits -- are competitive for a significant portion of circumstances where peak load is within several percentage points of T&D capacity.

3) Key facets of the evaluation framework used for this study are consistent with the increasing sophistication of T&D monitoring, control, operation, design, failure prediction, etc. technology and practices.

4) Prospects for DERs used for risk management are significantly better if DERs are readily redeployable.

5) Risk-reduction benefits associated with a multi-year T&D build-out using modular resources may be even more be attractive than benefits reflected for a single year evaluation.[5]

Endnotes
[1] Application of devices and equipment that interrupts a distributed generation customer’s normal load when distributed generation does not perform as contracted. An equal amount of customer load to the distributed generation capacity would be interrupted to prevent adverse consequences to the distribution system and to other customers.


