

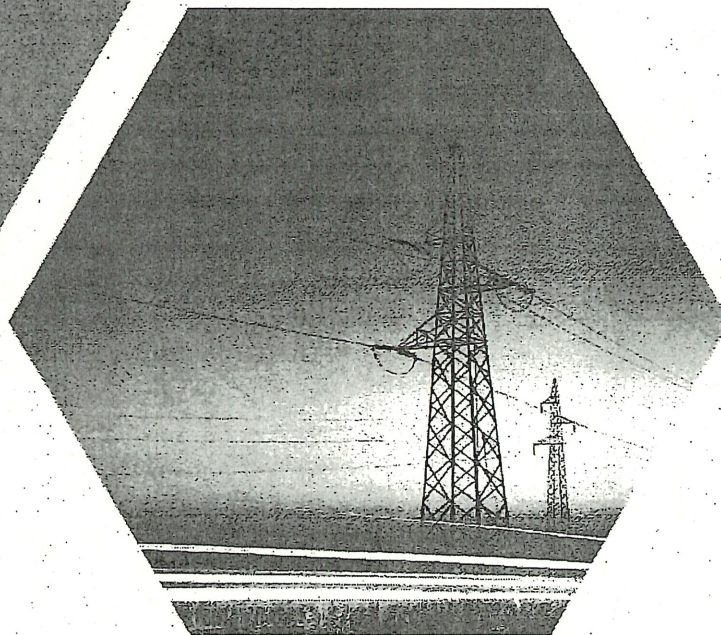
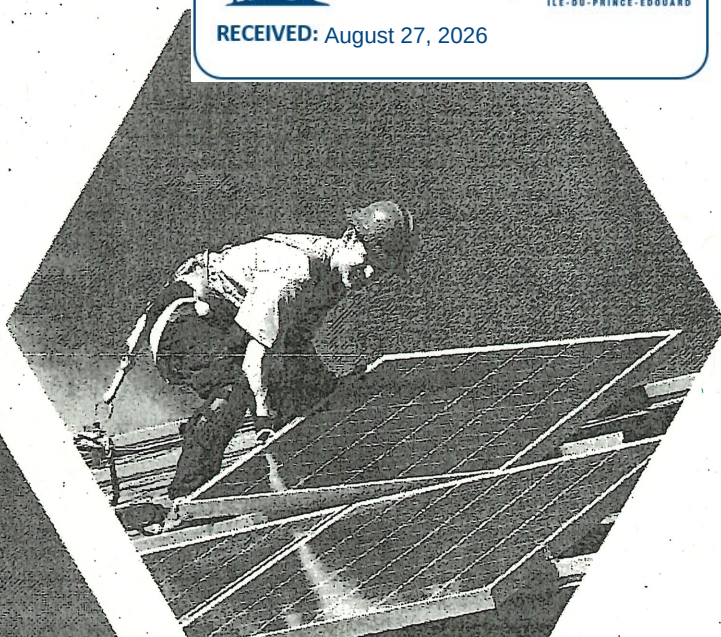
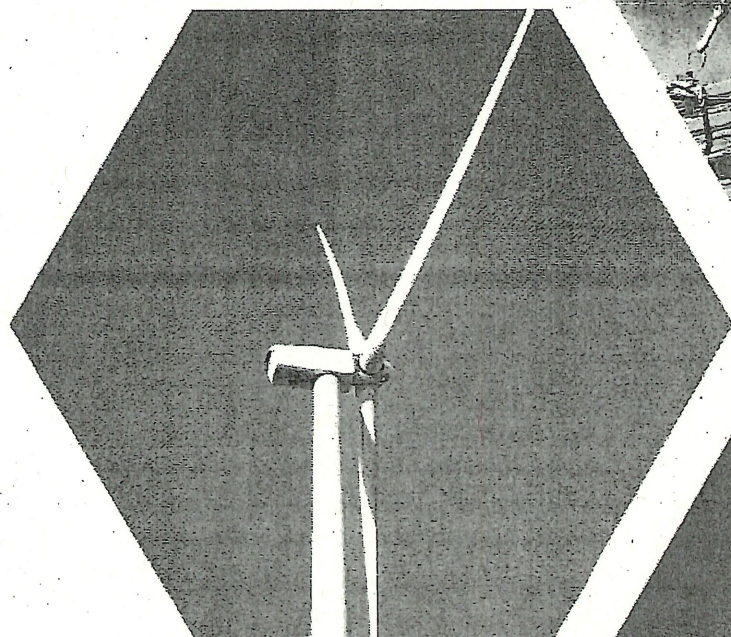


PRINCE EDWARD ISLAND
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Commission de réglementation et d'appels
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BEST PRACTICES IN INTEGRATED RESOURCE PLANNING

A guide for planners developing the electricity resource
mix of the future



Synapse
Energy Economics, Inc.



BERKELEY LAB

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resource across all megawatts (not just the next megawatt) or across a specific tranche of capacity. ELCC studies are complex, data- and time-intensive, and resource-specific. As discussed above, many RTOs and ISOs conduct their own ELCC studies which utilities can, and sometimes even must, apply to their own footprints (LBNL 2021c). Utilities that do not operate in RTO/ISO regions generally perform ELCC analysis in a modeling exercise separate from the IRP process.

Some utilities do not have time or resources to conduct their own studies for every resource considered. It is critical to avoid over-simplified assumptions that systematically disadvantage certain resource types. For example, if the utility performs a study of the ELCC for a 4-hour battery energy storage system, it cannot assume that the ELCC for an 8-hour system would be the same. Instead, the utility can look to studies from regionally comparable utilities and rely on their calculations, with reasonable and well-justified and documented adjustments as necessary, to account for differences across the utilities.

It is critical for utilities to avoid over-simplified assumptions that systematically disadvantage certain resource types.

Over the past decade, there has been considerable attention on calculating the ELCC for wind and solar and battery energy storage systems (BESS). There has been more limited attention on whether the traditional methods still used to value firm capacity for conventional thermal resources (such as coal, gas, or oil) — the Equivalent Forced Outage Rate Demand, or EFORD, methodologies — still result in sufficient resource adequacy. As the grid evolves, these traditional methods will not be sufficient.

EFORD-based methodologies value a resource's capacity based on the unit's historical outage rates at times it was needed. This means that modeling of fossil fuel resources usually uses average forced outage rates rather than weather-dependent forced outage rates, underrepresenting outage risk in periods of extreme weather. Recent high-profile extreme weather events, including Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, highlight the risks of availability of traditional fossil-fuel resources and correlated outages within a given power class of assets (e.g., natural gas) not captured by traditional capacity accreditation methodologies (S. Murphy, Sowell, and Apt 2019). These traditional methodologies (generally determined by RTOs) systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent by failing to account for outage variability, correlated outages, weather-dependent outages, and fuel supply constraints (AEE 2022; Astrapé Consulting 2022).

When viewed together, the use of the EFORD method for thermal resources and ELCC method for wind and solar is concerning:

- The EFORD methodology over-accredits capacity value for thermal resources.
- Utility customers are therefore paying for some level of capacity and reliability services from thermal resources that they do not actually provide.
- Wind and solar resources are being held to a higher standard with the ELCC methodology, resulting in systematic discrimination against them.

Traditional capacity accreditation methodologies have been found to systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent.