



ACEP
Alaska Center for Energy and Power

VALUE OF LOST LOAD (VOLL) LITERATURE REVIEW AND ADOPTION PATHWAYS FOR ALASKA

Prepared for the Railbelt Reliability Council (RRC)



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Executive Summary

This report supports the Railbelt Reliability Council (RRC) in estimating the Value of Lost Load (VoLL) in Alaska and integrating it into the Integrated Resource Plan. VoLL (\$/MWh) represents the value customers place on reliable electricity and reflects how much they are willing to pay to avoid outages (or the amount they would accept as compensation to endure an outage). Integrating VoLL into planning can help the RRC evaluate the costs and benefits of reliability-focused transmission investments and assess the economic impacts of short, targeted outages such as those caused by underfrequency load shedding.

The Alaska Center for Energy and Power (ACEP) examined theoretical and empirical VoLL estimation approaches used nationally and internationally, including in islanded and remote communities. Globally, four main approaches emerged: (1) survey-based methods that directly capture customers' willingness to pay (WTP); (2) revealed preference methods based on observed behavior; (3) macroeconomic models that relate output or GDP to electricity use; and (4) case studies that analyze real-world outage impacts. Crucially, the literature consistently reports that there is no universal VoLL: estimates vary widely by methodology, customer class, outage characteristics, backup availability, and local context. Thus, a range of VoLL estimates should be used to capture the customer mix, outage durations, and event types being evaluated for reliability planning and market design—particularly in Alaska due to its harsh climate, limited grid redundancy, seasonal economy, unique customer mix, and high curtailment exposure.

ACEP surveyed three commercial and industrial (C&I) customers in Fairbanks in September 2025. These surveys served to field test an Alaska-adapted version of the survey questions that underlie the ICE 2.0 model and provided insights into businesses' outage tolerance, operational impacts, and economic losses. Though limited in scope, these surveys provided initial VoLLs for C&I customers in Alaska, suggesting pronounced variation in outage tolerance and cost sensitivity. Outage tolerance declined sharply with duration and even short interruptions could be disruptive, particularly for businesses relying on electric heating or sensitive equipment. Per-MWh VoLL estimates declined with outage length, consistent with national studies, except when infrastructure damage increased losses. These early findings illustrate how customer characteristics influence outage costs in Alaska and highlight the need for regionally representative data to refine VoLL estimates for the Railbelt.

The report presents three possible VoLL estimation methods for Alaska: the **ICE approach**, the **hybrid approach**, and the **survey approach**. These options have different data requirements, levels of complexity, and estimated costs, as summarized below.

	ICE approach	Hybrid approach: ICE + field testing	Survey approach
Description	Uses the ICE 2.0 model and Railbelt data to estimate outage costs by duration and customer class. Not directly representative, moderate accuracy; low technical complexity and costs.	Combines ICE modeling with Alaska field testing to adjust model assumptions. Moderately representative, high accuracy for targeted factors; moderate technical complexity and costs.	Measures Railbelt customers' WTP to avoid outages through surveys. Fully representative of the Railbelt, with the highest accuracy; high technical complexity and costs.
Requirements	Existing Railbelt data.	Existing Railbelt data, new survey data.	Utility-provided data, new survey data.
ACEP-estimated timeline and costs	6 months \$75,000	8 months \$200,000	12 months \$300,000

Recommended use	Early modeling and preliminary planning.	Short- and medium-term planning and analysis.	Long-term regulatory and planning applications.
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A tiered dual approach is recommended to develop Alaska-specific VoLL estimates for the Railbelt:

1. **ICE approach:** A low-resource, low-cost analytical method that uses readily available tools and Railbelt data to quickly produce transparent VoLL estimates.
2. **Survey approach:** Comprehensive surveying captures Alaskan customers' WTP to avoid outages, offering highly accurate and representative VoLL estimates.

The suggested pathway provides useful VoLL estimates in the short term (ICE stage) while more accurate estimates can be obtained over time based on customer preferences and regional patterns (survey stage). ICE-based VoLLs can be used to support immediate planning efforts. Survey-based VoLLs may be more suitable for long-term transmission planning, investment decisions, and standards development.

As the literature indicates that there is no single VoLL, estimates should be obtained for different outage scenarios and customer mixes. For system-wide VoLL aggregation, two reference metrics are recommended: a VoLL weighted by system load share and a VoLL weighted by curtailment risk. The load-weighted VoLL is suitable for transmission planning studies where the entire system load is considered and all customers collectively benefit from improved reliability. The curtailment-weighted VoLL is suitable for studies that consider the customers most exposed to outages, i.e., the subset of customers likely to be curtailed first.

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Abbreviations

Abbreviation	Definition
ACEP	Alaska Center for Energy and Power
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AUFLS	Automatic underfrequency load shedding
BEA	Bureau of Economic Analysis
BESS	Battery energy storage system
C&I	Commercial and industrial
CBA	Cost–benefit analysis
CBCI	Customer billing contact information
CDF	Customer damage function
CIC	Customer interruption cost
CPI	Consumer Price Index
DA	Day-ahead (market)
DER	Distributed energy resource
EEA	Energy emergency alert
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GDP	Gross domestic product
GVA	Gross value added
GVEA	Golden Valley Electric Association
ICE	Interruption cost estimate
kWh	Kilowatt-hour
LASSO	Least absolute shrinkage and selection operator
LBA	Load balancing area
LBNL	Lawrence Berkeley National Laboratory
LDWI	Long-duration widespread interruption
LNR	Large non-residential
LOLP	Loss of load probability
MISO	Midcontinent Independent System Operator
MSA	Metropolitan statistical area
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market (Australia)
NERC	North American Electric Reliability Corporation
ORDC	Operating reserve demand curve
PI	Personal income
PJM	PJM Interconnection LLC
PoS	Point of supply
PUCT	Public Utility Commission of Texas
RRC	Railbelt Reliability Council
RTO	Regional transmission organization
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SMNR	Small and medium non-residential
SWCAP	System-Wide Offer Cap
UFLS	Underfrequency load shedding

VCR	Value of customer reliability
VoLL	Value of Lost Load
WTA	Willingness to accept
WTP	Willingness to pay

1. Report Scope and Objectives

The Energy Policy and Innovation team at the Alaska Center for Energy and Power (ACEP) has conducted a literature review of Value of Lost Load (VoLL) estimation methods as part of the VoLL Phase 1 project. This phase of the project aims to provide the Railbelt Reliability Council (RRC) with insights into the most appropriate and context-sensitive approach for conducting a VoLL study for Alaska. We began the project by examining how other regions estimate VoLL, with a focus on approaches relevant to Alaska's unique grid and climate conditions. This report presents VoLL concepts and methodologies, highlights key studies in the literature, and shares early findings from our research.

As part of this project, we reviewed a wide range of studies covering both theoretical and empirical approaches to estimating VoLL. The VoLL literature includes survey-based willingness-to-pay studies, macroeconomic analyses, and hybrid approaches across jurisdictions such as the U.S. (ERCOT, MISO, Midwest, Northeast), Europe (Germany, Ireland, Sweden, Norway), Australia and New Zealand, Africa (South Africa, Nigeria), and islanded or remote communities including Alaska. These studies examine residential, commercial, industrial, and very large business customers, and assess outage costs across different durations, timings, and reliability contexts, providing a diverse evidence base for understanding how outage impacts vary across regions, sectors, and estimation methods. Numerous papers have contributed to our understanding of VoLL estimation methods and regional applications; this report highlights studies that are particularly relevant to the Alaska context. These include detailed studies from the Lawrence Berkley National Lab (national, U.S.), ERCOT (Texas), MISO (Midwest U.S.), AEMO (Australia), Transpower (New Zealand), and small island communities in Alaska (Baik et al., 2023), each offering valuable insights into methodological approaches and adaptation strategies for cold-climate or remote grids.

This report aims to inform the RRC about the current knowledge of VoLL and potential pathways for applying it in Alaska. It is our understanding that the RRC intends to implement VoLL estimates into the Integrated Resource Plan to evaluate the costs and benefits of reliability-driven transmission upgrades. The RRC is also interested in understanding how VoLL estimates associated with short, targeted outages caused by underfrequency load shedding (UFLS) differ from average values representing all outage types.

The remainder of the report is structured as follows. Section 2 provides an overview of VoLL-related concepts and VoLL estimation methods, while Section 3 presents selected VoLL literature from the U.S. and abroad. Section 4 outlines the main findings from the literature and their application to the Alaska context. Section 5 presents early results from pilot surveys of small commercial and industrial customers in the Fairbanks area. Section 6 presents a decision matrix that compares three methodological options for VoLL estimation. Lastly, Section 7 summarizes the main findings from the study and offers recommendations to advance VoLL adoption in Alaska.

2. VoLL Concepts and Methods

2.1. Value of Lost Load

The Value of Lost Load (VoLL) is the economic cost to customers of electricity supply interruptions. It is typically expressed in dollars per kilowatt-hour (\$/kWh) or dollars per megawatt-hour (\$/MWh) and represents the amount customers are willing to pay (WTP) to avoid outages or the willingness to accept (WTA) compensation in exchange for enduring interruptions. VoLL varies across several dimensions, including customer characteristics (class, sector), outage conditions (duration, frequency, timing), contextual factors (grid configuration, geography), advance notification of outage, and availability of backup supply.

VoLL has many applications across planning and operations, including in transmission planning, reliability standards development, and investment prioritization. On the planning side, VoLL supports cost–benefit analyses of generation, transmission, and distribution investments by linking them to customers’ WTP for reliability. On the operations side, VoLL can inform the pricing of energy and reserves under scarcity conditions, inform the development and implementation of demand response or interruptible load programs, and help system operators weigh the trade-offs of controlled outages versus broader system collapse.

2.2. Outage Types

Electricity grid outages generally fall into three categories. First are large-scale, long-duration blackouts, where power is lost over large areas for days or weeks following catastrophic events such as the Northeast blackout of 2003 or Hurricane Sandy in 2012. These events require full system restarts and often major infrastructure repairs. Second are localized outages that last several hours and are usually caused by distribution failures or localized weather events such as tornadoes. Third are targeted interruptions that selectively curtail customers over short timeframes, such as rotating outages or load shedding in response to a drop in the frequency of the alternating current (i.e., UFLS), which is typically used to stabilize the system and avoid wider collapse.

The AKPRC-006-2 standard on automatic UFLS establishes the rules for designing, documenting, and maintaining coordinated UFLS procedures to protect the bulk power system during severe disturbances (Railbelt Reliability Council, 2017). It requires utilities and other responsible entities to set staged load-shedding blocks capable of handling the loss of the largest generator or transfers while avoiding unnecessary tripping during smaller events. Different utilities may have different strategies for handling UFLS. An example is provided by Golden Valley Electric Association (GVEA). GVEA’s UFLS procedure is structured around staged tripping (i.e., disconnection) of both industrial and distribution loads, coordinated with its battery energy storage system (BESS).¹ Large GS-3 industrial customers participate under special interruptible contracts, shedding motor-driven loads at three frequency thresholds. On the distribution side, about 30% of the system load is divided equally across three UFLS levels (10% per stage). Feeders are rotated among the stages so that the risk of disconnection is shared fairly. The BESS is programmed to ramp up in stepwise blocks at the same frequency thresholds, so each UFLS stage is preceded by or paired with BESS support, then industrial curtailment, and then feeder trips, providing a layered defense against cascading frequency collapse. Critical feeders—serving hospitals, police, fire stations, airports, water treatment, and downtown district heating—are excluded from UFLS. The scheme

¹ Based on email correspondence with GVEA in August 2025.

combines contractual interruptible load, distribution load rotation, and dynamic BESS support to arrest frequency decline while minimizing public disruption.

Beyond these three outage types, the VoLL literature refines outage typologies along several dimensions. One dimension is planned (where advance notice is provided) vs. unplanned interruptions. Unplanned interruptions result from storms or equipment failures and may have higher costs than planned interruptions. Another dimension is chronic vs. sporadic interruptions: chronic interruptions (e.g., recurring load shedding in South Africa) impose sustained economic drag, while sporadic but severe blackouts from high-impact, low-frequency events may inflict acute shocks. Some studies also include power quality events such as short voltage dips, sags, or momentary interruptions that, while not full outages, can cause significant financial losses in industries that use sensitive equipment, such as the semiconductor and digital services industries (Chowdhury et al., 2004).

2.3. VoLL Estimation Methods

As part of the literature review, a wide range of VoLL estimation studies were examined, many of which are listed in the references and bibliography (Appendices A1 and A2, respectively). These studies helped clarify key estimation methods and their regional applications both in the U.S. and abroad. VoLL estimation methods can be grouped into four categories: stated preference (survey-based), revealed preference, macroeconomic or production function, and case studies.

2.3.1. Stated Preference Methods

The stated preference approach involves surveying customers and asking them to respond to hypothetical outage scenarios. Several survey types fall under this umbrella, such as contingent valuation, contingent ranking, and conjoint analysis. Under contingent valuation, a researcher develops a hypothetical outage scenario and asks participants to provide either their willingness to accept (WTA) compensation in exchange for enduring an outage or their willingness to pay (WTP) to avoid an outage. In a contingent ranking survey, customers are asked to rank multiple outage scenarios that differ in both reliability and price. The rankings allow researchers to deduce the WTP for additional reliability. Direct survey methods are also used, particularly with non-residential customers, where respondents estimate the monetary loss they would incur during different outage scenarios. These survey results are then converted to VoLL estimates within confidence intervals based on standard econometric estimation and statistical techniques.

This final analytical step—converting customers’ stated outage costs into dollars per unit of energy—is necessary to incorporate survey results into future analysis and planning. However, it is important to recognize that these values were derived from specific outage scenarios. For instance, it might be inappropriate to use values derived from long outage scenarios in planning for short outages.

Generally, researchers agree that survey-based approaches are the most effective way to estimate a customer’s WTP to avoid a blackout or WTA compensation in exchange for enduring a blackout. However, full-scale surveys are often time-consuming, expensive, and sometimes impractical due to budget constraints, limited data availability, or differing research objectives. As a result, alternative methods are often used when comprehensive surveys are not feasible.

2.3.2. Revealed Preference Methods

Revealed preference methods observe market behavior decisions by electricity consumers to estimate VoLL. Investment decisions made by non-residential customers to prevent outages, such as installing backup generators or reliability-enhancing systems like batteries, can reveal a customer’s implicit

estimation of VoLL. Similarly, interruptible supply contracts and programs in which customers agree to reduce their electricity consumption during emergency events in exchange for discounted rates or direct payments can be used as a revealed preference mechanism for estimating VoLL. Additionally, demand curve estimation can be used to infer VoLL by analyzing how consumers adjust electricity consumption in response to changes in price. This method can be effective when high-frequency pricing and consumption data are available, and when price movements during scarcity events provide a wide range of price and consumption data.

2.3.3. Macroeconomic Methods

The macroeconomic approach uses a production function to estimate VoLL by linking the value of goods and services to the electricity consumption required to produce them. For non-residential customers, it estimates metrics such as the value of lost production, cost of overtime, cost of restarting equipment, and waste generated. For residential customers, it estimates metrics such as the loss of leisure time, the cost of spoiled goods, and stress. Macroeconomic approaches use macroeconomic data and other observable expenditures to estimate VoLL. Estimates are obtained for non-residential customers by taking the ratio of the gross economic output of a region, such as the gross domestic product (GDP) or gross value added (GVA), to the electricity consumption of industrial and commercial users in that region. Similarly, for residential customers, the ratio of their electricity bill to consumption can be used. More recently, economic studies have used proxy methods that assign a monetary value to residential customers' time based on income.

2.3.4. Case Studies

Case studies are performed using data from actual outages to estimate VoLL. The approach typically combines quantitative and qualitative data, including direct cost surveys, customer interviews, financial records, utility reports, and community-level feedback. Case studies can provide insights into the localized effects of outages, such as how a prolonged winter blackout affected critical services in a remote town or how a regional event disrupted supply chains and business operations. Case studies offer valuable context-specific understanding of VoLL; however, they are not statistically generalizable or transferable to other regions or systems. In other words, findings from a case study are closely tied to the circumstances of the event studied, limiting their use for system-wide or comparative VoLL estimation.

3. Review of VoLL Estimation Studies

3.1. Lawrence Berkeley National Laboratory

Overview

The Lawrence Berkeley National Laboratory's (LBNL) Interruption Cost Estimate (ICE) calculator is a publicly available tool for estimating outage costs to customers. It is built on customer damage functions (CDFs), which relate the outage costs to outage characteristics (e.g., duration, season, time of day) and customer attributes (e.g., usage, income, industry). These functions are estimated econometrically from a large meta-dataset of utility customer surveys that use WTP and WTA instruments. ICE 1.0 was developed in 2011 using survey data collected between 1989 and 2012, primarily from western and southwestern utilities, and was updated in 2015 and 2018 (Sullivan et al., 2018). ICE 2.0, launched in 2025, incorporates more recent surveys conducted between 2022 and 2024 from East and Midwest utilities and one utility in the Pacific Northwest (Larsen et al., 2025a, 2025b).

Methodology

ICE 1.0 is based on outage cost data from 34 datasets comprising over 105,000 customer survey responses from 10 utilities (Sullivan et al., 2009). LBNL refined the model in 2015 and 2018 to address two main gaps: regional variation and model precision (Schellenberg and Larsen, 2018; Sullivan et al., 2015). Adjustments included re-estimating customer class-level functions with additional datasets, adding a productivity-based regional factor for commercial and industrial (C&I) customers, and improving survey consistency by excluding atypical instruments. While these refinements improved function estimation, the dataset continued to reflect outdated usage patterns and a limited geographic scope.

ICE 2.0 is built on the ICE 1.0 framework and uses more recent, nationally representative surveys across 24 utility service territories. Residential customers were surveyed using a “one-and-one-half-bound” WTP contingent valuation design, while C&I customers completed direct cost surveys. These surveys captured outage costs for outage events ranging from momentary (≤ 5 minutes) up to 24 hours, across different times of day, seasons, and weekdays versus weekends. LBNL also tested hypothetical three-day outages to gauge coping strategies; however, these results were not included in model estimates. ICE 1.0 relied on legacy survey datasets that differed in question design and geographic focus and were generally limited to outages up to 12 hours. ICE 2.0 provides greater breadth and consistency of input data than ICE 1.0 while incorporating more recent electricity usage patterns and variables such as advance warning, backup generation, and work-from-home status (Larsen et al., 2025a). On the modeling side, ICE 2.0 applies more rigorous techniques—cross-validation, LASSO variable selection, functional-form tests for duration scaling, and bootstrap confidence intervals—to deliver more robust and reliable estimates.

ICE 2.0 is designed as a multi-phase national effort, with each phase adding utilities and refreshing the tool so that VoLL estimates track evolving technologies and user behaviors. Future ICE phases aim to expand coverage to underrepresented regions, including rural cooperatives in Alaska. Table 1 summarizes the costs to residential and non-residential customers derived from their answers to ICE 2.0 Phase 1 surveys, adjusted for inflation (Larsen et al., 2025b).

Table 1. Estimated costs per unserved MWh (VoLL) for residential and non-residential customers (2024\$/MWh).

Duration	Residential customers (\$/MWh)	Non-residential customers (\$/MWh)
≤5 minutes	18,562	536,366
2 hours	4,437	103,979
8 hours	2,728	56,622
24 hours	1,915	39,121

Key Takeaways

- For residential customers, interruption costs rise with income and usage; backup ownership dampens costs; and working from home raises costs.
- For non-residential customers, costs scale with usage, size, and industry type (especially for sectors unable to defer production), and receiving advance warning notices reduces costs.
- The CDF curves indicate that interruption costs increase convexly (i.e., at an increasing rate) with outage duration for residential and non-residential customers.
- Contextual factors such as the season, day of the week, advance warning, household income, industry type, and backup generator ownership systematically shift outage costs, making scenario-specific inputs important in cost–benefit studies.
- Bootstrapped confidence intervals provide transparent uncertainty ranges, allowing planners to avoid false precision.

3.2. Electric Reliability Council of Texas

Overview

The Electric Reliability Council of Texas (ERCOT) has estimated VoLL a number of times over the last decades. London Economics (2013a) conducted a literature review of VoLL studies and provided an initial VoLL based on a macroeconomic approach. More recently, Brattle Group presented the results and conclusions of a two-part VoLL study (Gibbons and Sanem, 2024). Part 1 entailed a literature review and provided an interim VoLL based on the ICE 1.0 calculator (Public Utility Commission of Texas, 2023a); Part 2 entailed a survey of retail customers throughout ERCOT to obtain more accurate VoLL estimates.

London Economics Study (2013)

London Economics (2013a) conducted a literature review to examine VoLL estimates in other jurisdictions and understand the methods used to derive them. While these estimates provided useful guidance, they were deemed insufficient proxies for ERCOT due to limited regional comparability. To estimate VoLL for non-residential customers in Texas, London Economics adopted a macroeconomic production function approach. This analysis used 2011 state-level GDP data from the U.S. Bureau of Economic Analysis (BEA) and electricity consumption data from the Energy Information Administration (EIA) Form 861. To focus the analysis on the ERCOT region, both load and economic activity data were adjusted to reflect ERCOT’s geographic boundaries. The adjustment for economic activity involved estimating an ERCOT-only GDP using the metropolitan statistical area (MSA) ratio and the personal income (PI) ratio. Texas’s GDP was scaled down by the ratio of the aggregated GDP of all MSAs in ERCOT to the aggregated GDP of all MSAs in Texas and by the ratio of the aggregated PI of ERCOT counties to the aggregated PI of all counties in Texas.

Brattle Group: Phase 1 (2023)

In 2023, Brattle Group reviewed 11 recent VoLL studies in North America, the UK, and Germany to identify insights that could inform their VoLL analysis (Public Utility Commission of Texas, 2023a). They then obtained an interim VoLL using econometric modeling adapted from LBNL's ICE framework. First, they applied the LBNL two-part regression model, which is the basis of ICE 1.0 (Sullivan et al., 2015), to ERCOT-specific outage and customer data to estimate VoLL for different customer classes (residential, commercial, industrial) and different outage scenarios (season, time of day). ERCOT-specific data were obtained from EIA Form 861, the U.S. Census Bureau, and ERCOT datasets. Second, they derived an interim system-wide VoLL as either a load-weighted average across customer classes (option 1) or a weighted average with C&I values capped by historical median values from the literature (options 2a, 2b, and 2c). These VoLL estimates are reported in Table 2, adjusted for inflation (Public Utility Commission of Texas, 2023a). The study also provided a preliminary VoLL estimate for residential customers using the bill-to-consumption method, i.e., based on the direct cost of electricity paid by retail customers. This VoLL was considered a lower bound since it understated VoLL for residential customers, as it did not consider the foregone value of leisure activities or indirect costs.

Table 2. ERCOT interim VoLL results (2024\$/MWh).

Customer class	Cost per unserved MWh (\$/MWh)
Residential	5,273
Small C&I	105,513
Medium and large C&I	81,149
Region-wide option 1	61,865
Region-wide option 2a (cap using all studies)	25,421
Region-wide option 2b (cap using all U.S. studies)	27,019
Region-wide option 2c (cap using all U.S. studies that test a 1-hour outage)	53,800

Brattle Group: Phase 2 (2024)

Phase 2 involved a survey of retail customers across ERCOT in 2024. The survey design was based on LBNL's ICE 1.0 customer surveys for the ERCOT region, with WTP or WTA outage questions for residential customers and direct cost questions for C&I customers. Outage scenarios varied by season (summer or winter), start time (morning, afternoon, or evening), day type (weekday or weekend), duration (5 minutes to three days), and advance warning (yes or no).

The final ERCOT-wide VoLL estimate from the survey was higher than the interim estimate. The 1-hour VoLL was \$35,685 per unserved MWh (2024\$/MWh), compared with the interim estimate of \$25,421 per unserved MWh (2024\$/MWh). Notably, the interim estimate remains within the 95% confidence interval of the survey-based estimate, which ranged from approximately \$25,000/MWh to \$53,000/MWh (2024\$/MWh). The wide confidence interval emphasizes the uncertainty in VoLL estimation. The ERCOT-wide VoLLs per unserved MWh and 95% confidence bounds for selected durations are reported in Table 3.

Table 3. VoLL per unserved MWh by customer class and outage duration (2024\$/MWh).

Outage duration	Residential	Small C&I	Medium and large C&I	ERCOT average	Lower ERCOT bound	Upper ERCOT bound
1 hour	3,964	666,907	22,721	35,685	24,721	53,384
2 hours	3,303	407,229	12,783	21,326	18,207	25,977
4 hours	2,039	253,454	8,064	13,340	11,447	16,016
8 hours	1,407	195,591	6,507	10,435	8,895	12,630
16 hours	1,091	239,280	9,463	13,581	10,597	18,716

The difference between the actual and interim VoLL estimates in the ERCOT study arises primarily from improvements in data quality. Customer input was gathered directly from ERCOT customers, making it a more accurate reflection of regional preferences and behaviors.

Key Takeaways

- As season and time-of-day effects were not significant, ERCOT presented the results based on a single representative scenario (weekday afternoon outage without advance warning in summer or winter). The VoLLs for small C&I customers were substantially higher than the VoLLs for residential customers because moderate per-event costs are divided by relatively low average usage. The VoLLs for medium C&I and large C&I customers fell between the values for small C&I and residential customers, consistent with the literature.
- VoLL estimates generally fell with outage duration because the same event cost spread over more unserved MWh. Advance warning of outages produced lower VoLLs for all customer classes.
- The report presented a VoLL scenario that excludes transmission-interconnected large C&I loads, which are seldom shed. This raised the ERCOT-wide 1-hour VoLL to \$61,394/MWh (2024\$/MWh). Nevertheless, ERCOT recommended using the \$35,000/MWh main-case value for planning.
- The final VoLL estimate was significantly higher than the interim estimate. This result suggests that survey-based results can capture customer perspectives that macroeconomic models may underestimate.
- Region-specific data collection is essential, as literature-based proxies alone are insufficient.

3.3. Midcontinent Independent System Operator

Overview

Midcontinent Independent System Operator (MISO) is the electric grid operator for the central United States, spanning 15 states and the Canadian province of Manitoba. It ensures reliable and affordable power flow and facilitates electricity buying and selling in its region. MISO uses two distinct VoLL constructs—the Pricing and System VoLLs—to improve price formation and market signals during reserve and energy shortages (Midcontinent Independent System Operator, 2024a). MISO obtained VoLL estimates by adapting the LBNL econometric meta-analysis of outage costs to its customer base and reliability context (Midcontinent Independent System Operator, 2024a).

Methodology

MISO used a two-step regression model tailored to different customer classes: residential, small C&I, and large C&I. These models link customer interruption costs to outage characteristics such as duration, timing, and advance notice while also incorporating MISO-specific variables such as regional load profiles, industry composition, household income, and the prevalence of backup generation. Using these MISO-specific parameters rather than U.S. averages ensures that the outage damage functions reflect the economic structure and demographics of the region.

MISO developed two VoLL constructs for market and system realities: the Pricing VoLL and the System VoLL. The Pricing VoLL informs the market price cap and scarcity pricing and is based on the customer groups most likely to face curtailment first, i.e., primarily residential customers. MISO combined residential and small C&I outage cost estimates using fixed weights of 85% and 15%, respectively. Large C&I customers were not included in the aggregation since their usage profiles and backup resources reduce their exposure during short-duration rotating outages. The 85/15 weighting produced a VoLL estimate of \$3,500/MWh in 2007. When updated with 2023 data, the VoLL estimate increased by 300–400%, yielding \$13,640/MWh (2023\$/MWh). MISO currently sets the cap at \$10,000/MWh to balance market discipline with price stability. In addition, MISO has a circuit breaker. After 4 hours of energy emergency alert (EEA)-3 load shed, the pricing VoLL decreases to \$5,000/MWh; if the emergency spans the day-ahead (DA) close, both DA and real-time pricing VoLLs are set to \$5,000/MWh for the next operating day; if this situation persists through another DA close, they drop to \$2,000/MWh and then reset to \$10,000/MWh when the emergency ends.

The System VoLL captures the social cost of unserved energy across all customers and is used to scale the loss of load probability (LOLP) portion of the operating reserve demand curve (ORDC). It is calculated as a load-share weighted average using the class composition of MISO demand—roughly 35% residential, 31% small C&I, and 34% large C&I—resulting in substantially higher values that reflect the disproportionate costs borne by C&I users. In practice, load balancing areas (LBAs) cannot isolate specific customer classes during outages since residential and C&I loads often share circuits. Table 4 summarizes the VoLLs by customer class and duration, adjusted for inflation (Midcontinent Independent System Operator, 2024a).

Table 4. MISO load class VoLL components by outage duration (2024\$/MWh).

Outage duration	Residential	Small C&I ^a	Large C&I	System VoLL ^b	VoLL ^c
1 hour	4,465	68,311	30,341	37,976	14,041
2 hours	2,491	42,443	20,992	24,239	8,484
4 hours	1,521	31,222	18,731	18,883	5,975
8 hours	1,043	28,071	22,504	18,849	5,097
12 hours	857	26,238	24,763	18,883	4,664

^a This value excludes the services segment of small C&I, which reduces small C&I by 18%.

^b Load weights: 35% residential, 31% small C&I, and 34% large C&I.

^c 2007 VoLL weighting: 85% residential, 15% services.

Key Takeaways

- Pricing VoLL is anchored to customers with the lowest WTP; MISO assumes that rotating outages focus primarily on residential load (85% weight) with a legacy 85/15 residential/small-C&I mix.
- Small and large C&I customers have higher class VoLLs and inevitably see some curtailment in wide-area events; even a 15% inclusion of non-residential load materially raises a price-based VoLL.
- MISO demonstrated the importance of incorporating national meta-analysis data (LBNL) into a region-specific framework rather than merely using generic values.
- Weighting assumptions strongly influence VoLL estimates and depend on how these are used.

3.4. Australian Energy Market Operator

Overview

The Australian Energy Market Operator (AEMO) conducted an extensive value of customer reliability (VCR) study to generate updated, segment-specific estimates of how much customers value a reliable electricity supply. The Australian Energy Regulator (AER) publishes VCR values for different customer groups (residential, businesses, and very large businesses), segmented by climate zone and remoteness, for defined outage attributes such as duration up to 12 hours, summer/winter, peak/off-peak, and weekday/weekend.

Methodology

The 2024 VCR study (Australian Energy Regulator, 2024) used a survey-based stated preference approach grounded in contingent valuation and choice modeling. While the methodology remained consistent since 2019 (Australian Energy Regulator, 2019), the 2024 study used detailed consumption data based on meter readings for individual customers. The AER calculates the VCR for each customer class (or customer segment in AEMO terminology) as follows. First, it elicits the WTP via surveys (residential and business customers) and direct cost surveys (very large business customers) to avoid specific outage scenarios. Then, it uses the respondents' consumption data and AEMO metering data to estimate the unserved energy for 32 unique outage scenarios. Finally, it weighs the unserved energy values for each outage scenario by its historical frequency to produce a weighted average VCR in \$/kWh for each customer segment. Regional (national, state, and territory) VCRs are aggregated by load weighting across customer segments. Specifically, outage frequency weights are applied within each sector to calculate its VCR, whereas the aggregated regional VCR is primarily load-weighted across sectors.

Surveys were administered to residential and small business customers across all five National Electricity Market (NEM) jurisdictions. Almost 6,000 customers (3,600 residential, 2,323 business) were surveyed to understand customer preferences across a range of outage scenarios and measure the WTP to avoid outages. For large businesses (over 10 MVA peak demand), including directly connected customers, the study asked 37 customers to estimate the cost they would incur for outages of different durations. Tables 5–8 provide the residential, business, very large business, and system-wide VCR values, respectively. These values were converted from 2024 AUD to 2024 USD using the average exchange rate in 2024 (Exchange Rates UK, 2025).

Table 5. Residential VCR values (2024\$/MWh).

Jurisdiction	VCR (\$/MWh)
New South Wales	25,422
Victoria	32,482
Queensland	23,812
South Australia	32,013
Tasmania	23,548
Australian Capital Territory	33,452
Northern Territory	20,249
NEM	27,369

Table 6. Business VCR values (2024\$/MWh).

Customer segment	VCR (\$/MWh)
Agriculture	14,681
Commercial	22,691
Industrial	22,097

Table 7. Very large business VCR values (2024\$/MWh).

Customer segment	VCR (\$/MWh)
Services	21,839
Industrial	8,063
Mines	7,014
Metals	35,497

Table 8. System-wide VCR values (2024\$/MWh).

Jurisdiction	VCR (\$/MWh)
New South Wales	20,407
Victoria	23,608
Queensland	16,990
South Australia	21,985
Tasmania	12,530
NEM	19,794

Key Takeaways

- For residential customers, duration is the dominant driver of WTP. Seasonal effects are strong, while peak-time and day-of-week effects are weak. Factors like electrification (e.g., electric vehicle charging at home), working from home, and high-profile outage events with media coverage influence customer perceptions and household WTP.
- For small and medium business customers, outage durations are a driver of WTP, with agriculture showing the most sensitivity. Seasonal effects are statistically significant for agriculture, while

commercial customers prefer avoiding weekday and peak outages. Businesses with backup options have higher WTP than those without.

- Businesses are heterogeneous even within the same industry. Accordingly, their preferences depend on their activities, which makes it difficult to draw conclusions about their WTP drivers.
- The mines and industrial sectors show high VCR \$/kWh at very short outages (e.g., 10 minutes) due to fixed shutdown and startup costs, with diminishing costs per kWh as the duration increases. The services sector sees outage costs rising with duration, with long outages (e.g., 12 hours) being particularly costly. For the metals sector, outage costs rise substantially after 3 hours.

3.5. Transpower New Zealand Limited

Overview

Transpower's VoLL study provides planners with VoLLs that can be applied at each point of supply (PoS)² for unexpected customer outages (Transpower, 2018). The study translates customer preferences and large-user costs into sector- and outage-specific VoLLs (\$/MWh), then applies weights based on the local load mix, season, type of day, and observed duration profile to derive PoS-specific figures. The obtained PoS VoLLs are used to manage the risk associated with their assets, inform service target categorization, and support cost-benefit analysis. The PoS VoLL results generally range between \$17,000/MWh and \$40,000/MWh and center around \$25,000/MWh (2018\$/MWh). In 2024 dollars, these values range between \$12,887/MWh and \$30,323/MWh, centering at \$18,952/MWh.

Methodology

Transpower commissioned PwC and Advisian to survey consumers. PwC (2018) used contingent valuation and discrete choice modeling to determine the WTP of residential and business customers. They completed an online survey of 404 residential customers and 619 business customers. Business customers are categorized by type (primary, commercial, industrial) and subcategorized by size (small, large). "Primary" covers the agriculture, forestry, and fishing industries. The study considered attributes such as the duration of the interruption (10 minutes, 1 hour, 5 hours, 8 hours), season (summer, fall/shoulder, winter), type of day (weekday, weekend), and time of day (morning, day, evening, night). PwC analyzed customers' WTP to avoid an outage and WTA compensation for unreliability. Ultimately, PwC used WTP values for VoLL calculations since the WTA was much higher than the WTP and less aligned with ex-ante investment decisions. They then combined the stated value of an outage with unserved energy estimates inferred from customer monthly bills and reconciled hourly load profiles (provided by TransPower) to estimate VoLL.

Advisian surveyed a small selection of New Zealand's largest electricity users, with a focus on directly connected consumers and major electricity users. They gathered large users' process-specific costs (e.g., backup costs, damage, overtime costs, revenue losses) through direct cost surveys via email, phone, and in-person interviews, assessing outage durations up to 24 hours (10 minutes, 1 hour, 3 hours, 5 hours, 12 hours, 24 hours).

In the final stage of the study, Transpower combined the segment-and-scenario VoLLs obtained from the survey (e.g., the commercial, winter, weekday, 1-hour VoLL) with the consumer demand composition (estimated using metering and demand data) at each PoS and the historical distribution of interruption

² While PoS is not defined in Transpower (2018), Transpower (2000, p. 5) defines a PoS as "the substation or other location at which a customer's assets are physically connected to the grid assets (whether for injection or offtake)."

durations (2008–2016). The PoS-level VoLL was then obtained as the sum of the relevant segment-and-scenario VoLLs with weights for the season, day type (weekday/weekend), decomposed sector demand mix at each PoS, and duration distribution. PoS VoLLs reflect the customer mix and outage profile. Thus, a PoS with a high residential load will have a low VoLL, while a PoS with high business and industrial loads will have a high VoLL. Table 9 summarizes VoLL estimates for New Zealand. These values are derived from PwC’s (2018) VoLL estimates; more detailed tables and the methodology used to derive these numbers are provided in Appendices B1 and B2.

Table 9. New Zealand VoLL estimates (2024\$/MWh).

Outage duration	Residential	Small C&I	Large C&I
10 minutes	7,799	196,887	58,628
1 hour	4,041	35,997	15,793
5 hours	2,878	8,670	5,923
8 hours	2,343	6,064	3,560

Key Takeaways

- VoLL decreases as the interruption duration increases. This finding is likely due to the influence of fixed costs associated with interruptions and is consistent across customer classes.
- Residential VoLL is significantly lower than the VoLL for businesses, which drives the PoS VoLL spread (i.e., PoS with higher business loads have higher VoLLs). Thus, the composition of demand at each PoS primarily drives interruption impacts, with VoLL as an important but secondary factor.
- Residential customers value reliability most in the evening. Their strongest driver for VoLL is the time of day. While the VoLL per MWh declines with duration, modest impacts are seen with variations in season and day type (weekend vs. weekday).
- Small commercial customers have among the highest per-MWh costs, caused by the spread of high fixed costs over low hourly usage. They report that outages cost more in daytime and evening weekday scenarios than in night and weekend scenarios. They face higher costs than large commercial customers due to high per-MWh VoLLs for short events.
- Industrial customers estimate high VoLLs during business hours and are sensitive to operating schedules and process constraints. Small industrial customers face higher outage costs than large industrial customers due to higher energy intensity.
- For the agriculture industry, VoLL trends resemble those of small C&I customers. Short outages during active work windows have high VoLL estimates, with primary VoLL drivers being the season and the time of day.

3.6. Alaska

Overview

Baik et al. (2023) aimed to quantify the economic and societal costs of long-duration, widespread power interruptions (LDWIs) in electrically islanded communities, with a focus on Alaska and a U.S. territory in the South Pacific. Islanded populations face increasing short-term risks (e.g., tropical storms, cyclones, and hurricanes) and long-term risks (e.g., rising sea levels, droughts, and floods) that threaten isolated energy systems and can cause outages that last multiple days and affect large geographic areas. By developing region-specific CDFs and cost estimates, the study sought to inform investment and policy decisions to enhance the reliability and resilience of energy systems in such vulnerable settings.

Methodology

The study adopted a three-part approach encompassing scenario development, survey implementation, and CDF construction. The first step, scenario development, involved identifying the hazards most relevant to each study region—for example, volcanic activity and tsunamis in the Gulf of Alaska, and severe winter storms in Interior Alaska—and assessing their potential impacts on electricity infrastructure. This process included analyzing historical disaster patterns, evaluating community preparedness measures such as backup generator availability, and estimating the expected duration and geographic extent of outages. Based on this information, hypothetical outage scenarios were developed and reviewed by energy experts, utility personnel, and regulatory stakeholders to ensure they were relevant.

Next, the survey design was tailored to capture how outages affect various customer groups. For residential customers, the survey focused on eliciting the maximum WTP to avoid specific outage scenarios. For non-residential customers, the survey sought detailed estimates of lost revenue, additional operating costs, and any cost savings realized during power interruptions. For the public sector, the survey sought to estimate not only operational costs but also changes in response times, injuries, and deaths under outage conditions, enabling monetization of societal costs through standard metrics such as the value of a statistical life and medical treatment costs. The team conducted three survey rounds between 2021 and 2022, one in each region, targeting four customer classes: residential, small and medium non-residential (SMNR), large non-residential (LNR), and public sector services. Given the small size of the studied communities and limited survey infrastructure, recruitment relied on convenience sampling. Outreach channels included utility email lists, radio announcements, flyers, and direct outreach by local partners.

Using the survey data, duration-dependent cost functions were constructed for each customer segment, covering outage durations of 6 hours, two days, and seven days. The direct costs from surveys were then supplemented with indirect costs, which were estimated using regional economic multipliers (RIMS II input–output factors) and a literature-based multiplier range (one-half to two times the direct cost estimates) where the RIMS factors were unavailable. For public sector impacts, the reported changes in injuries and deaths were monetized using national and regional benchmarks. Table 10 provides a summary of the VoLLs for Alaska communities calculated from duration-dependent CDFs (Baik et al., 2023).

Table 10. Direct and indirect power interruption costs based on CDFs for one-week outages (2024\$/MWh).

Customer class	Gulf of Alaska	Parts of Southeast and Interior Alaska
Residential	350	240
SMNR	16,600	52,500 to 105,000
LNR	281,000	57,000 to 114,000
Public	156,000	103,000 to 207,000

Key Takeaways

- Residential customers reported modest absolute outage costs compared to C&I customers, but their costs increased sharply with duration. Their WTP values captured intangible burdens such as comfort loss, stress, health risks, and food loss.
- SMNR customers reported some of the highest per-customer outage costs. Their direct costs were dominated by lost sales, inventory spoilage, and immediate operational downtime. Limited redundancy and dependence on perishables or foot traffic (e.g., grocery, retail, food services) amplified outage costs. Backup generation ownership was far lower among small businesses than large firms, making them more exposed to frequent or prolonged disruptions.

- LNR customers reported not only revenue and production losses but also significant restart costs, equipment damage risks, and increased overtime expenditures once power returned.
- Public sector customers reported high direct operational costs, but their societal costs often dwarfed those financial impacts. Long outages could significantly increase injuries and deaths, particularly due to disrupted health services and emergency response delays that, when monetized, make societal costs a major component of total losses.
- Region-specific CDFs are critical for isolated systems, as they capture how outage costs escalate steeply with duration. Isolated systems differ sharply from one another and from mainland U.S. contexts due to their unique hazard profiles, backup prevalence, sector mix, and so on, reinforcing the need for locally derived estimates.

4. Findings

4.1. Methods: Relevance and Caveats

4.1.1. Survey-Based Methods

Survey-based methods can capture customer-specific values through direct elicitation (e.g., WTP) for a wide variety of scenarios with varying parameters such as seasonality, duration, and timing. However, survey-based methods face several challenges. First, they are subject to hypothetical bias and may overstate actual preferences. Second, they may capture embedding effects (e.g., difficulty in distinguishing the value of avoiding one outage versus five outages). Third, survey results may be context-specific and lack generalizability. Lastly, studies often find discrepancies between WTP and WTA, whereas in theory these should not differ. These issues underscore that while stated-preference surveys are essential for gauging customer outage costs, the findings must be interpreted with caution. Careful survey design (e.g., framing realistic outage scenarios and prompting for specific cost categories) can mitigate some biases, but result uncertainty remains a key limitation of survey-based VoLL estimates.

4.1.2. Macroeconomic Methods

Macroeconomic or proxy methods tend to underestimate outage costs. These methods link VoLL to economic metrics such as electricity tariffs or regional GDP per kWh. Macroeconomic, production function, and GDP-based methods are easy to implement and scale, and provide benchmarks and points of comparison that are easy to interpret. However, these methods do not account for consumer surplus beyond what customers pay on their bills and do not capture all economic activity. Moreover, they do not reflect heterogeneity in outage impacts and smooth over timing, sector, and duration effects, and often miss the indirect and induced economic impacts of outages. Planners should treat such VoLLs as low-end estimates and supplement them with estimates from more granular methods when evaluating reliability investments.

4.1.3. Real-World Case Studies and Result Generalization

VoLL estimates based on case studies (e.g., post-event assessments) are rare due to the infrequency of large outages. While insightful, the findings from such studies are highly context-specific and difficult to generalize, as they are shaped by local conditions, timing, and preparedness. Post-event studies are constrained by data collection challenges and the difficulty of quantifying intangible costs. Their results are informative but context-specific and should generally be used as a complement to broader survey and modeling approaches.

4.2. No Single VoLL

Most studies in the literature agree that there is no single “correct” VoLL, as estimates depend heavily on multiple factors rather than a single universal metric. Table 11 summarizes the key factors that influence VoLL estimates.

Table 11. Key factors and attributes that influence VoLL.

Factor	Attributes
VoLL use	Transmission planning, scarcity pricing
VoLL estimation method	Stated preference, macroeconomic, revealed preference, case study
Outage scenario	Duration, notice, season, timing
Customer class	Residential, commercial, industrial
Backup availability	Yes or no

When applying VoLL in cost–benefit analysis for transmission planning, both academic and gray literature emphasize that estimates must reflect the customers and outage types that a planned transmission project may affect. VoLL should be treated as a range of values rather than a single value since the value of electricity depends on the end use, timing, outage duration, and customer characteristics that are imperfectly captured by customer classes. A single static VoLL can therefore be misleading.

From a microeconomic perspective, households and businesses value the services enabled by electricity, not kilowatt-hours per se. The mix of services at risk during an outage shifts with the hour of the day, outage length, and availability of substitute services. This makes VoLL inherently time- and context-dependent, and aggregating to a regional average inevitably sacrifices detail. Gorman (2022) recommends triangulating across methods, surveys, proxies, and revealed-preference evidence to characterize VoLL. Even then, uncertainty remains high due to data noise. Thus, cost-effectiveness planning—i.e., setting a reliability target and finding the lowest-cost way to meet it—should remain central (Gorman, 2022), with cost–benefit analysis as informed by VoLL playing only a complementary role.

4.2.1. VoLL Variation by Application

VoLL is currently used in two basic ways. First, it is an essential input in cost–benefit analyses of investments for increasing reliability: VoLL measures the benefits, or at least the direct benefits to customers.³ Second, VoLL is widely used by system operators in large markets to inform pricing decisions and rules that take effect when energy or reserves are scarce. Two prominent examples are the use of VoLL to help set energy price caps and the use of VoLL in combination with LOLP to determine how much a system operator is willing to pay for additional operating reserves.

ERCOT

ERCOT uses two VoLLs: one for planning and one for operations. The planning VoLL is based on Brattle’s survey-based study (Gibbons and Sanem, 2024), which the Public Utility Commission of Texas (PUCT) approved for planning activities (e.g., cost–benefit studies for transmission investment planning) and reliability standards. Brattle estimated VoLLs for each customer class and then applied load weighting to derive system-wide VoLLs. For example, the ERCOT-wide, 1-hour VoLL is about \$35,000/MWh for an outage occurring on a weekday afternoon with no advance notice (Gibbons and Sanem, 2024).

³ Societal benefits of reduced outages may exceed direct customer benefits when other parties such as government, community organizations, or businesses bear some of the outage costs. For instance, if a customer is fully insured against food spoilage, their WTP falls, yet the insurer bears the full cost of the spoiled goods.

By contrast, ERCOT’s operations VoLL is used as a policy parameter along with the ORDC to shape scarcity prices. In ERCOT documentation, VoLL is set equal to the System-Wide Offer Cap (SWCAP), as required by Texas Statute §25.505(g)(6)(E). Following the 2011 heat wave, the SWCAP was gradually increased from \$3,000/MWh in 2012 to \$9,000/MWh in 2015 (Public Utility Commission of Texas, 2023b). It was then reduced to \$2,000/MWh in response to Winter Storm Uri in February 2021, and subsequently increased to \$5,000/MWh in January 2022 (Electric Reliability Council of Texas, 2024).⁴ Since the ORDC ties VoLL to SWCAP, the operational VoLL is \$5,000/MWh, a level that was chosen to ensure “appropriate generation is available using market-based mechanisms” and to incentivize “demand response during scarcity events while limiting extraordinary financial liability for all market participants and protecting consumers” (Public Utility Commission of Texas, 2023b, p. 38). In essence, PUCT determined that ERCOT, on behalf of its customers, shall place a value of no more than \$5,000 on an additional MWh and shall therefore procure neither energy nor operating reserves for prices higher than \$5,000 per MWh.

MISO

MISO uses two VoLLs: a Pricing VoLL and a System VoLL. The Pricing VoLL (\$10,000/MWh) is the market price cap, and the administrative price is applied if firm load is shed (EEA-3); in other words, the Pricing VoLL governs price increases during periods of scarcity and load-shed hours. The uses of the Pricing VoLL are summarized in Figure 1. Until late 2024, MISO used a Pricing VoLL range to calculate reliability benefits in transmission planning (Midcontinent Independent System Operator, 2024b, 2024c), spanning from the approved VoLL of \$3,500/MWh (based on outdated 2007 accounting) to the more realistic VoLL of \$10,000/MWh (based on present-day accounting). Following a filing with the Federal Energy Regulatory Commission, MISO raised its reference VoLL from \$3,500/MWh to \$10,000/MWh in 2025 (Midcontinent Independent System Operator, 2025).

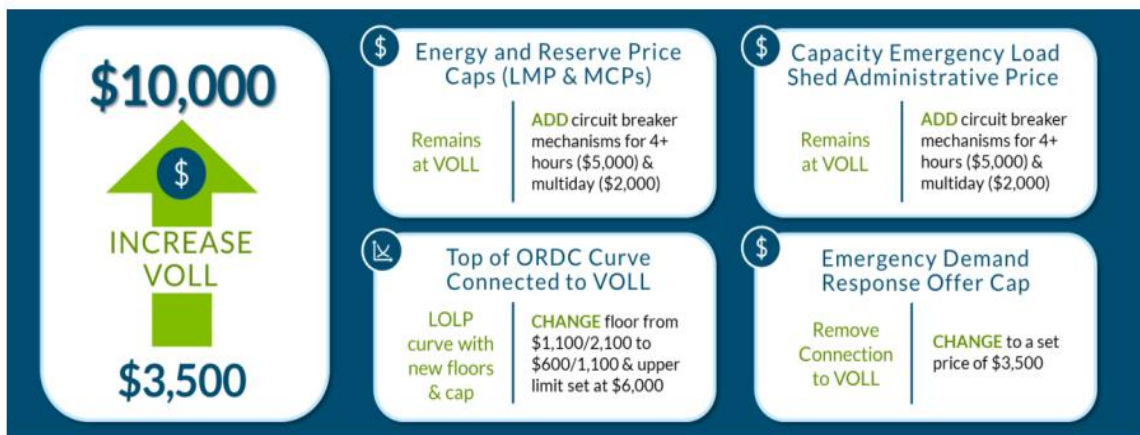


Figure 1. Uses of MISO’s Pricing VoLL (MISO, 2024).

MISO’s System VoLL (\$35,000/MWh) is a scaling factor that multiplies the LOLP to shape the ORDC so that real-time prices rise smoothly as the reserve risk increases. MISO pairs this with an ORDC ceiling of

⁴ While PUCT and the Federal Energy Regulatory Commission (FERC) have adopted the more recent VoLL of \$35,000/MWh, news reports indicate that this value will “not be used to update the ORDC or any current market-design elements” (Kleckner, 2024).

\$6,000/MWh and two ORDC floors of \$600/MWh and \$1,100/MWh to improve congestion management during small reserve shortfalls and to align with emergency-offer floors.

New Zealand

The Electricity Authority's (2021) cost-benefit analysis of automatic underfrequency load shedding (AUFLS) used a \$25,000/MWh VoLL along with a VoLL GDP adjuster. The GDP adjuster accounts for the real increases in VoLL as New Zealand's economy grows, i.e., the effect of the increasing per capita income: as customers' income grows, they value kWh more. The VoLL was adopted from Transpower (2018), which provides a VoLL range of \$17,000–40,000 per MWh with a central estimate of \$25,000/MWh (2018\$/MWh). Transpower planning documents also cost involuntary load shedding at these values (Transpower, 2017). In these documents, VoLL serves purely as a monetization tool: it converts unserved energy during a blackout into dollars (mean load \times restoration time \times VoLL), and that value is then scaled by the modeled reduction in blackout risk under the revised AUFLS design.

The Electricity Authority sets administered scarcity prices with reference to customers' VoLL but keeps them distinct to provide a clear, consistent signal to markets during tight supply. It recommends that, because scarcity prices cannot reflect every factor that influences the "true" VoLL, they should reference VoLL without trying to match it. The Electricity Authority anchors the scarcity price in 2025 to Transpower's (2018) VoLL range after indexing it to 2024 USD values using the producer price index (Electricity Authority, 2025a, 2025b).

4.2.2. VoLL Variation by Outage Duration

Outage duration is one of the strongest drivers of interruption costs. As outages lengthen, total outage event costs climb, first from fixed and setup losses (spoiled work, setup restart, routine disruption) and then from ongoing flow losses. Long events also entail indirect losses, for example, from resource spoilage or health impacts. However, the cost per unserved kWh typically falls after the first few hours, as fixed costs are spread over more lost energy. Using a single, duration-agnostic VoLL therefore risks underestimating both the high costs of short outages and the compounding impacts of long ones.

The literature consistently embeds duration into VoLL estimation. ICE 2.0 confirms that both residential and non-residential customers face higher total costs as outages lengthen, although the cost per kWh declines after the first few hours. Residential costs escalate sharply between momentary and multi-hour events. Small C&I customers are most sensitive to short outages, while larger firms accrue higher absolute losses over long events. ERCOT's 2024 survey shows the same pattern, reporting rising per-event costs from 1 hour to 16 hours but falling \$/MWh (Gibbons and Sanem, 2024). Similarly, Australia's 2024 VCR update provides values by outage length, cautioning against applying one value across scenarios (Australian Energy Regulator, 2024).

4.2.3. VoLL Variation by Customer Class

The literature consistently finds that VoLL varies significantly by customer class and sector. Averaging VoLL across all customers obscures these differences.

C&I customers face much higher per MWh costs than residential customers since an outage mainly causes inconvenience and minor economic loss at home, whereas commercial and especially industrial customers can have very high VoLLs due to lost production or sales. For instance, Transpower reports a residential VoLL well below the VoLLs of all business classes across seasons, times of day, days of the week, and outage durations (Transpower, 2018). Consistent with this, ERCOT (Gibbons and Sanem, 2024) found that residential VoLLs were the lowest, medium and large C&I VoLLs were four to six times higher, and small

C&I VoLLs were the highest. Furthermore, Larsen et al. (2025b) reported lower residential VoLLs compared to non-residential VoLLs across various attributes. The results reported by the Australian Energy Regulator (2024) are also consistent with the literature, with business VCR higher than residential VCR.

Heterogeneity within sectors is explained by multiple attributes. Small C&I customers have the highest \$/MWh because fixed outage losses are spread over relatively low energy use (Chowdhury et al., 2004; Dzobo et al., 2012; Sullivan et al., 2018). For instance, a small business might not consume much energy, but even a short outage can halt operations and result in substantial revenue losses, inflating the cost per kWh of interruption. Additionally, since small C&I customers are less likely to prepare for outages by purchasing backup generation than large C&I customers, this leads to generally higher VoLLs for small C&I customers. In particular, Gibbons and Sanem (2024) found that the service sector usually has the lowest VoLL, while manufacturing and mining have the highest VoLLs.

The drivers of inter-sector heterogeneity for non-residential customers in the ICE 2.0 model are industry indicators, usage intensity, and advance warning (Larsen et al., 2025b). However, ICE 2.0 does not segment small, medium, and large C&I customers. ICE 1.0 recognized two non-residential classes: (i) small and medium non-residential and (ii) large non-residential. For ICE 2.0, Larsen and colleagues compared two segmentation options—three size bins (small, medium, large) and two size bins (small, medium-to-large)—to a single, continuous non-residential CDF. They found that the segmented models delivered very limited statistical improvements for small and medium customers and were worse for the national dataset and large customers.

4.2.4. VoLL Variation by Timing and Seasonality

A consistent finding in the literature is that the timing of an outage can matter as much as its duration. Interruption cost studies repeatedly emphasize that VoLL is time-dependent, with costs rising and falling with daily routines, the day of the week, and seasonal weather, though regional factors can also alter the cost pattern.

Time of Day

Many surveys include the time of day as an attribute, but findings vary. In an ICE 1.0 study (Sullivan et al., 2015), small C&I customers reported the highest costs in the afternoon, while households valued electricity most in the evening for cooking, childcare, and comfort. Medium and large businesses were less sensitive to the time of day. New Zealand surveys (Transpower, 2018) found a similar split—higher evening costs for households and afternoon peaks for business customers. By contrast, Larsen et al.'s (2025b) ICE 2.0 study reported no statistically significant differences between morning and evening. Brattle's ERCOT survey (Gibbons and Sanem, 2024) also found little variation in residential WTP across times of day. In Australia, peak effects were modest for households and significant for commercial customers (Australian Energy Regulator, 2024).

Day of Week

Outages on weekdays generally carry higher costs because of greater economic activity. The ICE 2.0 study (Larsen et al., 2025b) estimated higher interruption costs for non-residential weekday events, and both the Australian Energy Regulator (2024) review and New Zealand surveys (Transpower, 2018) reported stronger weekday effects for businesses, with only modest variation for households. Evidence from South Africa adds nuance: some retail and hospitality firms reported greater weekend losses when outages overlapped with peak trading hours (Dzobo et al., 2012; Herman and Gaunt, 2008).

Seasonality

Seasonal extremes increase interruption costs, though cost patterns vary across customer classes. The ICE 2.0 study found higher costs for households in winter but no significant seasonal effects for businesses. The Australian Energy Regulator (2024) review identified significant seasonal preferences for the agriculture industry and households, with a tilt toward avoiding summer outages, and modest effects for commercial customers. South African surveys highlighted high summer burdens linked to cooling and refrigeration (Dzobo et al., 2012; Herman and Gaunt, 2008). However, ERCOT’s 2024 survey found no systematic seasonal differences (Gibbons and Sanem, 2024).

Overall, timing clearly shapes VoLL, though the magnitude and direction depend on the customer class and region. While exceptions exist, the literature supports embedding temporal granularity—time of day, day of week, and season—into VoLL estimation.

4.3. Application of VoLL to the Alaska Railbelt

4.3.1. Existing VoLL Models

Utilities and system planners have often relied on generic VoLL estimates derived from national surveys or other regions’ studies, such as the ICE calculator or interim values from ERCOT and MISO. Recent studies highlight the limitations of this approach, especially for local grids with unique characteristics. Applying such national-average models to a remote, cold-climate system like Alaska’s Railbelt can misstate true costs since local economic activities, climate-related risks, and customer preparedness differ from the national norm. Similarly, borrowing VoLL figures from other jurisdictions can be problematic. Regulators often prefer to develop local VoLLs via targeted customer research rather than rely on imported estimates, as in the case of ERCOT. Given the isolated, winter-peaking grid of the Alaska Railbelt, system planners need VoLL estimates that are grounded in customers’ experiences and WTP to ensure reliability decisions are based on accurate, context-specific information.

The ICE 2.0 tool can serve as a starting point for Alaska, but it should not be used without local validation. In particular, four caveats should be considered when applying ICE 2.0 to the Alaska context. First, the geographic transferability of ICE 2.0 is limited. The survey territories are predominantly East/Midwest and one Pacific Northwest region, which means that ICE 2.0 is not climate- or industry-specific to Alaska (Figure 2). The Alaska Railbelt faces significant challenges associated with cold climate and remote isolated systems (permafrost impacts, limited interconnections, extreme cold, heating dependence, etc.) that are not captured in ICE-surveyed territories. For example, in some Railbelt communities, even a 6-hour outage in winter can be life-threatening if heating fuel systems or furnace blowers are disrupted. ICE 2.0 does not fully capture this cold-climate sensitivity or the resulting experiences, behaviors, and preferences of Alaskan customers.

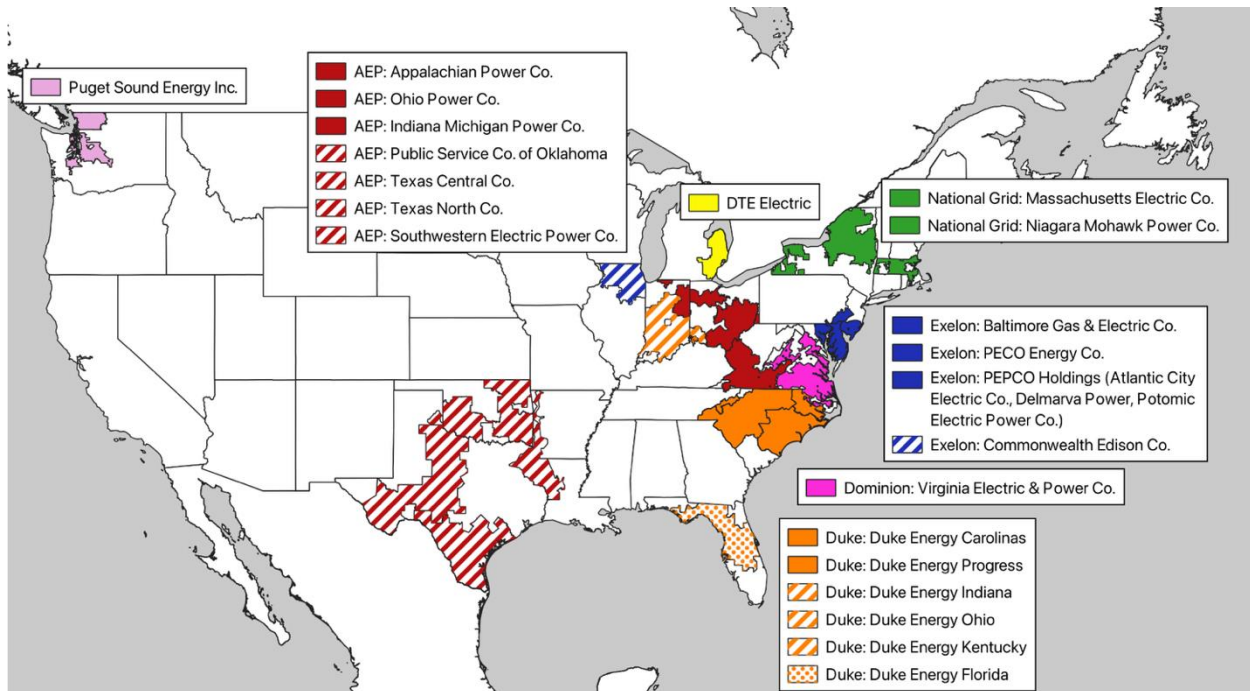


Figure 2. ICE 2.0 Phase 1 sponsoring utilities and distribution service territories (Larsen et al., 2025b).

Second, ICE 2.0 collapses all non-residential customers into a single category. The non-residential CDF parameterizes the healthcare and manufacturing sectors explicitly, with “all other industries” as a catch-all category. Critical Railbelt industries such as oil, gas, mining, and tourism fall in the “other” bucket. These industries differ significantly from the manufacturing-focused, service-heavy industries covered in the ICE 2.0 survey footprint. As a result, the outage costs for Railbelt-critical industries may not be accurately captured by ICE 2.0.

Third, outage duration scaling in ICE 2.0 requires careful interpretation. The LBNL results clearly show that although total outage costs increase as duration lengthens, the incremental cost per hour declines over time; after the first few hours, customers may adapt to the outage through backup generation or activity shifts (Larsen et al., 2025b). In Alaska’s cold climate, this pattern may not hold. Baik et al.’s (2023) study of islanded Alaska communities demonstrates that outage costs continue to rise sharply with duration even in the short term (6 hours), as heating systems, water pumps, and other survival-critical services all depend on electricity. In such contexts, per-hour costs may escalate rather than taper, as households and businesses have fewer alternatives and less redundancy. This suggests that while ICE 2.0 provides a useful baseline for short outages, its duration curves are not adjusted to cold climates like Alaska’s and may underestimate the true time sensitivity of outage costs on the Railbelt.

Fourth, ICE 2.0 fits a log-based duration model where the outage cost depends on the natural logarithm of duration and its square, which guarantees a rising total cost but flattens the marginal cost per hour as the outage continues. This method incorporates customer adaptation (backup use, activity shifts) over a 24-hour window. In cold-climate systems, heating and critical services depend on electricity, so hardship can compound with each hour lost. Quadratic duration functions (Baik et al., 2023) capture this convex escalation: the total cost increases while the marginal costs also increase (each additional hour of outage is more costly than the last). Thus, ICE 2.0 damage function curvatures should be stress-tested against convex alternatives to avoid understating early-hour and cold-weather vulnerability on the Railbelt.

4.3.2. Customer Weighting in VoLL Estimation

The mix of customers considered for load shedding—that is, customers likely to be curtailed during a shortage—can alter VoLL estimates significantly. Because the VoLL per MWh equals the dollar loss per outage event divided by unserved MWh, shifting the exposed mix toward low energy usage customers (e.g., small C&I customers) tends to raise VoLL even when the per-event outage losses are modest. Including high energy usage industrial customers tends to lower the VoLL for the same per-event outage losses. Thus, accounting for the customer mix exposed to potential load shedding is an important step toward more accurate estimates of reliability.

Customer classes often share transmission and distribution circuits. It is not technically feasible for load-balancing areas to target a single customer type (e.g., residential). Load shedding is often reliability-driven and constrained by grid topology, UFLS schemes, interruptible programs, and other load characteristics. MISO conducted an LBA survey to understand which customer classes would initially be shed in a wide-area request (percentage of total load shed). The results showed that residential customers (48%) were most likely to be load shed, followed by large C&I customers (30%) and small C&I customers (22%). Thus, MISO uses a Pricing VoLL that reflects the customer classes most likely to be curtailed first. MISO's Pricing VoLL (\$10,000/MWh) calibration recognizes that firm load shedding is concentrated on residential feeders (85%), which have the lowest 1-hour summer outage VoLL. However, other high-valued load classes (15%) would inevitably be curtailed during such an event, resulting in a VoLL of \$13,640/MWh for a 1-hour summer outage (2023\$/MWh).

ERCOT uses a different approach. Rather than weighing VoLL based on the customer classes likely to be curtailed, ERCOT provides scenarios that reflect how VoLL varies with load-shedding exposure across customer classes. ERCOT estimates a system-wide, survey-based VoLL by load-weighting across classes. It also presents an alternative scenario that excludes large industrial customers, which are interconnected directly to the transmission system and account for approximately 10% of large C&I customers and 58% of the large C&I annual load. These customers are typically not curtailed in operations since transmission service providers focus on distribution-connected customers for load shedding. In the distribution-only case, the per-event costs for medium and large C&I customers (which do not include the transmission-interconnected large industrial customers) are lower, but their average hourly load also decreases significantly. Accordingly, the ERCOT-wide 1-hour VoLL rises to \$60,974/MWh—about \$26,000/MWh higher than the primary scenario estimate (2024\$/MWh). ERCOT notes that this higher value may be more relevant when valuing measures that reduce load-shed risk, although it retains the system-wide figure for planning comparability with other jurisdictions.

Unlike ERCOT and MISO studies, Australia and New Zealand reports on VoLL cover multiple LBAs and regional transmission networks. These reports keep VoLLs heterogeneous by design and publish segment-specific VCRs for defined outage attributes. AER calculates the VCR in the same way for each customer class. It elicits the WTP to avoid defined outage scenarios, estimates the unserved energy for each scenario from consumption data, and finally applies weights based on historical outage data to obtain a VCR \$/kWh value for each segment and scenario. Regional (national, state, and territory) VCRs are aggregated via load weighting across customer segments (Australian Energy Regulator, 2024).

4.3.3. Alaska-Specific Conditions

The Railbelt faces outage conditions unlike most U.S. systems. Harsh winters, isolated electric grids, limited system redundancy, and a highly seasonal economy all shape how customers experience and value reliability.

Climate, Geography, and Backup

Short winter outages in Alaska occur under harsher conditions than in most of the U.S., with markedly less daylight and lower, sustained subzero temperatures. Heating is predominantly natural gas in Anchorage (72%) and fuel oil in Fairbanks (71%) (U.S. Census Bureau, 2023). These households still rely on electricity for blowers, pumps, and controls, leaving even non-electric-heated homes vulnerable during outages. Moreover, 20–27% of households in these regions report wood as a secondary heating source (Daniels and Paruszkiewicz, 2016).⁵ By comparison, this percentage is about 7% for the U.S. (U.S. Energy Information Administration, 2020). Thus, a larger share of households use wood as a secondary heat source in the Railbelt region, which mitigates the immediate space heating loss during outages but leaves electricity-dependent end uses (e.g., booster pumps, refrigeration, lighting) unprotected. Consequently, even brief outages can cause costly issues such as frozen pipes during cold spells and long winter nights.

As in other U.S. states, critical facilities in Alaska likely maintain standby generation, and small commercial sites and multifamily buildings rarely have whole-building backup. However, the Railbelt faces a higher residual risk than most U.S. states due to several factors. Extreme cold and limited winter daylight make the loss of electric services more consequential, while remoteness and sparse road networks constrain drive-to-power coping options. Moreover, complex fuel logistics and constrained performance in cold weather limit generator autonomy, and the Railbelt's long, lightly paralleled transmission corridor makes area-wide, simultaneous short interruptions more plausible. In addition, storms, icing, and permafrost introduce more failure modes and can slow power restoration.

Grid Topology and Redundancy

The large continental grids in the Lower-48 have multiple parallel transmission paths and dense distribution meshes that confine faults locally and keep nearby substitutes (stores, services) energized. By contrast, the Railbelt is a long, isolated corridor with limited external ties and few alternative distribution paths. Upstream contingencies can propagate widely unless arrested. To preserve stability, UFLS schemes shed load in blocks (Railbelt Reliability Council, 2017); a single contingency (generator trip or transmission fault) can therefore produce simultaneous short outages over large areas, and remoteness often increases response times. Moreover, automatic grid controls typically restrict outage events to hours rather than days.

EIA 861 reliability estimates of Railbelt utilities (2023 data) reflect more frequent, short-duration, wide-area outages than in many continental systems. For detailed calculations based on EIA 861, see Appendix B3. In August 2024, an upstream contingency led to simultaneous interruptions for over 70,000 customers across two neighboring Railbelt utilities (the Chugach Electric Association and the Matanuska Electric Association), with most services restored the same evening (Klint, 2024; Nordyke, 2024). This is a classic example of a short, wide-area impact outage. Similarly, GVEA's controlled load-shed protocol rotates 30–60-minute interruptions across feeders during supply shortfalls, producing brief, simultaneous outages over a broad area to preserve system stability (Golden Valley Electric Association, 2025).

Sectoral and Seasonal Economy

Short Railbelt outages primarily translate into lost sales, canceled services, and temporary production or logistics delays for C&I customers. Alaska's seasonal and sectoral patterns are characterized by time-critical seasonal peaks. For example, commercial fishing is compressed into short summer openers; nearly

⁵ As Alaska-specific statistics on household or C&I backup power are not available, Railbelt backup coverage should be treated as uncertain and heterogeneous.

90% of tourists arrive between May and September (McKinley Research Group, 2024); and construction must fit into 120 frost-free days before freeze-up. Subsistence and indigenous activities add further nuance. Freezer outages can spoil a year’s harvest of salmon, moose, or berries, while communication losses during narrow weather or travel windows can create safety and opportunity costs.

Across the board, researchers stress that VoLL is not a universal constant and must be interpreted in context. Factors like the regional economic structure, climate, grid configuration, consumer habits, and climate all influence outage costs. Accordingly, VoLL estimation for the Railbelt requires a region-specific approach rather than reliance on national averages.

4.4. VoLL Estimates Across Jurisdictions

4.4.1. System-Wide VoLL

Table 12 presents VoLL estimates by jurisdiction and customer class, drawing from the studies reviewed in Section 3 (ICE 2.0, ERCOT, MISO, AEMO, and Transpower New Zealand). These VoLLs represent a 1-hour outage expressed in 2024\$/MWh. As ICE 2.0 does not provide VoLL for a 1-hour outage, this value was extrapolated from the 2-hour and 8-hour outage VoLLs. The extrapolated VoLLs are within the ranges reported by most other jurisdictions. While each jurisdiction applies its own assumptions and customer segmentation, the comparison offers a high-level snapshot of VoLL estimation across the world.

Table 12. VoLL across jurisdictions for a 1-hour outage (2024\$/MWh).

Jurisdiction	Residential	Small C&I	Large C&I	System-wide
ICE 2.0	4,722	111,872	111,872 ^a	-
ERCOT	3,964	666,907	22,721	35,685
MISO	4,465	68,311	45,383	36,032
AEMO	27,369	21,938 ^b	18,103 ^c	19,794
NZ	4,041	35,997 ^d	15,793 ^d	18,952

^a ICE 2.0 does not distinguish between small and large C&I customers, so the same VoLL is used for both.

^b Calculated using VCR values and load share data from the Australian Energy Regulator 2024 (Appendices A–F) for small C&I customer segments: agriculture (8.6%), commercial (80.7%), and industrial (10.7%).

^c Calculated using VCR values for large C&I customer segments (services, industrial, mines, and metals) and an unweighted average due to a lack of load share data.

^d See Appendix B2 for the calculation method.

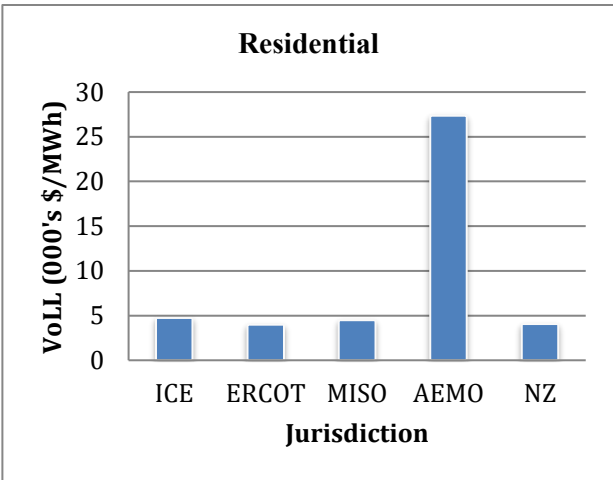


Figure 3. Residential VoLL (2024\$/MWh).

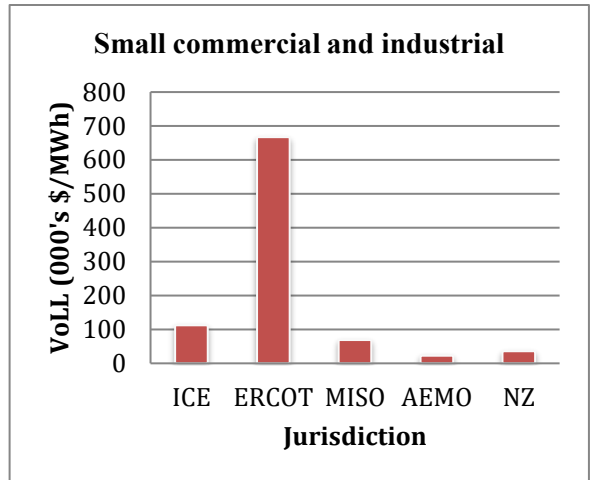


Figure 4. Small C&I VoLL (2024\$/MWh).

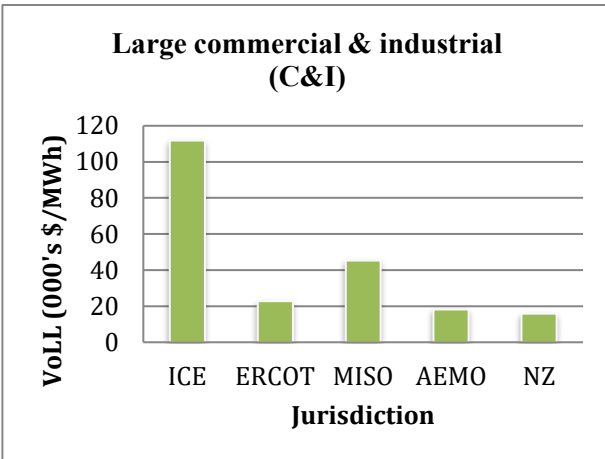


Figure 5. Large C&I VoLL (2024\$/MWh).

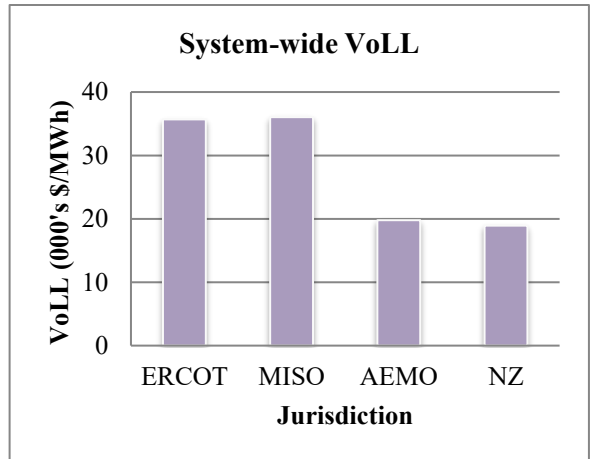


Figure 6. System-wide VoLL (2024\$/MWh).

Across jurisdictions, residential VoLLs cluster around \$4,000–\$5,000 per MWh (Figure 3), reflecting relatively similar WTP responses from households in different markets. Australia (AEMO) is an outlier at \$27,369/MWh. Australia’s residential VoLL is significantly higher due to the high WTP to avoid outages attributed to increased electrification, work from home, and customer perception around recent widespread outages. Furthermore, a revised (lower) unserved energy dataset, which mathematically increases the \$/MWh value, also increased VCR levels considerably since 2019. In addition, the AER survey methodology explicitly includes seasonal and heat-related impacts, raising outage costs for households.

Small C&I customers exhibit the widest variation (Figure 4), ranging from approximately \$22,000/MWh in AEMO to over \$666,000/MWh in ERCOT. ERCOT’s high VoLL arises from a denominator effect: moderate outage costs are divided by the very small average electricity use of small C&I customers, which inflates the VoLL. This wide range also illustrates the sensitivity of small businesses, particularly those without backup generation, to short outages and loss of critical equipment. The MISO and ICE results are relatively close to the AEMO estimate, suggesting that regional economic structures and survey design significantly influence these values.

For large C&I customers (Figure 5), VoLL estimates are more consistent across jurisdictions, generally between \$15,000–\$45,000 per MWh, suggesting that large industrial customers face measurable but more manageable losses due to access to redundancy, self-generation, or process scheduling flexibility. Since the ICE model does not distinguish between small and large C&I customers, both customer segments are attributed the same non-residential VoLL (Table 12), which contributes to the outlier VoLL shown in Figure 5. This result highlights a customer segment limitation of the ICE model.

The system-wide VoLL (Figure 6), representing an energy-weighted aggregate across all customer classes, ranges between \$18,000/MWh and \$36,000/MWh. These values align with those adopted for reliability planning across major energy markets and provide a useful benchmark for evaluating outage costs and reliability investments.

4.4.2. Application of ICE 2.0 to the Alaska Context

To explore preliminary VoLL usage in Alaska, the ICE 2.0 model was used to estimate VoLL for the Railbelt, combining ICE cost-per-event data (national sample) with Railbelt-specific unserved energy estimates obtained from EIA (U.S. Energy Information Administration, 2025). Average energy consumption (or unserved energy) was calculated for residential, commercial, and industrial customers (Table 13). The results, adjusted for inflation based on the estimates reported by Larsen et al. (2025b), provide insight into how Railbelt customers may value reliability during outages.

For a 1-hour interruption, the estimated VoLL is approximately \$7,600/MWh for residential customers, \$258,000/MWh for commercial customers, and \$8,200/MWh for industrial customers. The system-wide VoLL, based on the 2024 load share of residential (35%), commercial (42%), and industrial (23%) customers, is \$112,820/MWh, driven upward by the small C&I segment. These results do not reflect Railbelt-specific socioeconomic indicators, seasonality, outage characteristics, or other key factors that can influence VoLL. Hence, these estimates are not fully representative and should be treated as an illustrative example.

ERCOT capped the small C&I VoLLs to the median C&I value as seen in its literature review to calculate its interim VoLL (Public Utility Commission of Texas, 2023a). Capping the small C&I VoLLs at the average small C&I VoLL across ICE, MISO, AEMO, and NZ (i.e., \$59,530/MWh), the system-wide VoLL of the Railbelt is \$29,567/MWh using the 2024 load share of the Railbelt. The ERCOT small C&I VoLL, being an outlier value (Figure 4), was omitted to avoid skewing the average VoLL. The estimated Railbelt-wide VoLL indicates that even brief outages carry significant economic consequences for small C&I customers, particularly those whose operations depend on a continuous power supply.

Table 13. ICE 2.0 model application to Alaska with limited Alaska inputs.

	Outage duration	Cost per event (ICE)	Unserved energy per Railbelt customer per event (kWh)^a	Cost per unserved MWh (Railbelt) (\$/MWh)
Residential	≤5 minutes	1.85	0.06	29,628
	1 hour ^b	5.75	0.75	7,653
	2 hours	10.80	1.50	7,191
	8 hours	26.30	6.01	4,379
	24 hours	56.13	18.02	3,115
Non-residential (commercial)	≤5 minutes	627	0.51	1,233,369
	1 hour ^b	1,572	6.10	257,752
	2 hours	2,923	12.20	239,569
	8 hours	6,354	48.80	130,206
	24 hours	13,019	152.50	85,370
Non-residential (industrial)	≤5 minutes	627	15.00	39,240
	1 hour ^b	1,572	191.73	8,201
	2 hours	2,923	383.46	7,622
	8 hours	6,354	1533.84	4,143
	24 hours	13,019	4793.25	2,716

^a The average unserved energy per customer per event in kWh is derived from the average annual energy use per customer from EIA (U.S. Energy Information Administration, 2025) for residential, commercial, and industrial customers. Average hourly use is calculated as total annual use/(8760 × number of customers) and then multiplied by the duration of the event to determine the average use per customer per event.

^b Extrapolated from 2-hour and 8-hour outages.

4.4.3. Seasonality in VoLL Estimates

Seasonality in ICE Modeling

Seasonality plays an important role in shaping VoLL estimates across regions and customer classes. The ICE 1.0 model assumes a summer weighting of 33% for both residential and non-residential customers, whereas the revised ICE 2.0 model assumes a 33% summer weighting only for residential customers (Larsen et al., 2025a). These model assumptions are based on the work of Larsen et al. (2025b), who found that seasonality was statistically significant only for residential customers, with consistently higher outage costs in winter than in summer for the same outage duration. For example, in 2024\$, a 24-hour outage costs \$62 per event in winter and \$51 in summer (Figure 7); Larsen and colleagues attributed this 22% difference to the greater reliance on electric heating, lighting, and household activity during colder, darker months. Thus, seasonality is incorporated in the residential ICE 2.0 model as a statistically significant variable, whereas it is not considered in the non-residential model.

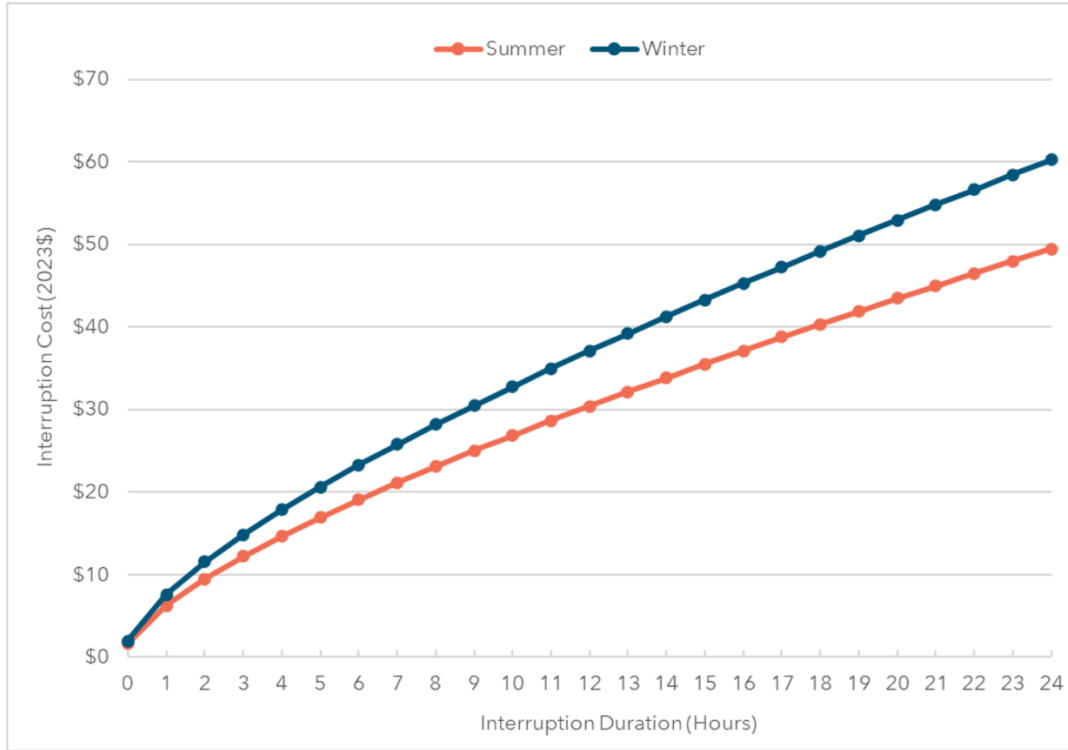


Figure 7. Residential interruption cost in summer and winter as estimated by the ICE 2.0 model (2023\$).

Seasonality in ERCOT VoLL

Seasonal differences are observable across residential and large C&I customers in the interim ERCOT VoLLs (Public Utility Commission of Texas, 2023a). These estimates were obtained using the ICE 1.0 model, which assumes the same summer weighting for residential and non-residential customers, and ERCOT data. The interim VoLLs were then replaced by refined VoLLs following an ERCOT-wide survey in 2024, which was based on the updated ICE 2.0 model and did not find statistically significant seasonal differences across customer classes (Gibbons and Sanem, 2024). Thus, the survey-based results did not include separate outage VoLLs for summer and non-summer months.

Residential VoLLs for 1-hour outages ranged between \$3,641–\$5,524 per MWh in summer and between \$2,511–\$3,892 per MWh in non-summer (Table 14), with the highest values occurring during summer mornings or nights and the lowest during non-summer afternoons. On average, summer VoLLs were 30% higher than non-summer VoLLs for the same time-of-day conditions. Large C&I customers (the manufacturing sector and other sectors) saw, on average, 24% higher VoLLs for 1-hour outages in summer than in non-summer months (Table 15).

Table 14. ERCOT VoLL for residential customers for a 1-hour outage (2024\$/MWh).

Timing of interruption	VoLL
Summer morning/night	5,524
Summer afternoon	3,641
Summer evening	4,834
Non-summer morning/night	3,892
Non-summer afternoon	2,511
Non-summer evening	3,390

Table 15. ERCOT VoLL for large C&I customers for a 1-hour outage (2024\$/MWh).

Sector	Timing of interruption	VoLL
Manufacturing	Summer	173,679
Other	Summer	68,717
Manufacturing	Non-summer	134,619
Other	Non-summer	50,946

Seasonality in MISO VoLL

Seasonality is observable across customer segments in the MISO VoLL estimates derived from the ICE 1.0 model and MISO-specific data (Midcontinent Independent System Operator, 2024b). Non-summer outages generally imposed higher costs than summer outages, particularly for small and medium-sized commercial customers, reflecting their greater dependence on electricity for heating, lighting, and production continuity during cold months. However, outages imposed lower costs on residential and large C&I customers in the non-summer months. It is important to note that these VoLL estimates are based on the outdated ICE 1.0 model, which assumes the same seasonality effect for all customer classes (Larsen et al., 2025a). Re-estimating VoLL with the updated ICE 2.0 model, which assumes that seasonality is only statistically significant for residential customers, may produce different results.

Residential VoLLs for 1-hour outages ranged between \$2,867–\$3,456 per MWh in non-summer and between \$3,367–\$4,465 per MWh in summer (Table 16), with the highest values occurring during summer off-peak periods and the lowest during non-summer afternoon peaks. On average, summer VoLLs were 15% higher than non-summer VoLLs for the same time-of-day condition. For small C&I customers (Table 17), 1-hour outages showed the highest seasonality in the dataset, with 45–55% higher VoLLs in non-summer (\$115,000–122,000 per MWh) than in summer (\$79,000–84,000 per MWh). Small C&I customers often lack backup generation and are highly exposed to equipment, heating, and inventory losses when outages coincide with winter cold snaps. By comparison, large C&I customers (Table 18) exhibited more modest seasonality, with VoLLs approximately 10% lower in non-summer than in summer. For manufacturing, the VoLL was \$62,271/MWh in non-summer and \$69,722/MWh in summer; for other sectors, the VoLL was \$27,099/MWh in non-summer and \$30,341/MWh in summer.

Table 16. VoLL for MISO residential customers for a 1-hour outage (2024\$/MWh).

Timing of interruption	VoLL
Summer, off-peak	4,465
Summer, afternoon	3,367
Summer, evening	4,060
Non-summer, off-peak	3,801
Non-summer, afternoon	2,867
Non-summer, evening	3,456

Table 17. VoLL for MISO small C&I customers for a 1-hour outage (2024\$/MWh).

Sector	Timing of interruption	VoLL
Non-construction, non-manufacturing	Summer, off-peak	83,353
Non-construction, non-manufacturing	Summer, morning	79,013
Non-construction, non-manufacturing	Summer, afternoon	80,728
Construction	Summer, off-peak	182,926
Manufacturing	Summer, off-peak	149,917
Non-construction, non-manufacturing	Non-summer, off-peak	122,374
Non-construction, non-manufacturing	Non-summer, morning	115,594
Non-construction, non-manufacturing	Non-summer, afternoon	118,520

Table 18. VoLL for MISO large C&I customers for a 1-hour outage (2024\$/MWh).

Sector	Timing of interruption	VoLL
Non-manufacturing	Summer	30,341
Manufacturing	Summer	69,722
Non-manufacturing	Non-summer	27,099
Manufacturing	Non-summer	62,271

Seasonality in Australian and New Zealand VoLLs

Both Australia (Australian Energy Regulator, 2024) and New Zealand (Transpower, 2018) provide season-specific VoLLs. These estimates are not discussed in this report due to their limited contextual applicability to Alaska, as both nations have summer-peaking energy systems. The New Zealand VoLL estimates, reported in Appendix B1, capture seasonality and were used to calculate the system-wide VoLL calculations.

5. Preliminary Results from Customer Interviews

The ACEP team interviewed C&I organizations in the Fairbanks region in September 2025. The survey instrument was adapted from the non-residential (business) questionnaire used in the ICE 2.0 tool, with modifications to reflect Alaska-specific operating conditions. The interviews used structured questions designed for a future survey, serving as a field test to assess the feasibility of collecting data from a larger sample. Although several businesses expressed strong interest in participating, many noted that the fall is a particularly busy period and thus not ideal for survey participation. Consequently, only three in-person interviews of C&I organizations were completed. The sample comprises professional services, hospitality, and light industrial businesses operating in Alaska. Due to the small sample size, results are presented as illustrative observations and should not be interpreted as representative of broader customer groups.

5.1. Respondent Characteristics

The first respondent was a small, office-based business employing 10 full-time staff. The company operates a 6.6 kW solar photovoltaic system that meets 100% of the facility's electrical demand but does not have any backup generation capability. Uninterruptible power supply units and line-conditioning devices are leased or rented to protect sensitive equipment. The second respondent was a hospitality business employing between 50 and 100 individuals, including 25 part-time and 50–70 full-time seasonal employees. The facility uses pumps for heating that are highly sensitive to voltage fluctuations and does not have any backup generation equipment. The third respondent was an agricultural processing business with two full-time employees, one part-time year-round employee, and 30 seasonal workers (14 full-time and 16 part-time). The business leases or rents backup generators and surge protectors to maintain operations and protect equipment during outages. It uses a 26 kW natural gas generator that can operate as backup for up to three days and meet 100% of its electrical demand during an outage. Key characteristics of the three respondents are summarized in Table 19.

Table 19. Characteristics of the survey respondents.

Respondent	Business type	Employees	Annual revenue estimate	Power backup	Electricity cost share
1	Professional services (office-based consulting)	10	\$4 million	Leased or rented	<1% of total expenses
2	Hospitality (lodging)	50–100	\$15 million	None	10% of total expenses
3	Agricultural processing (greenhouse farming)	20–30	-	Leased or rented	4% of total expenses

5.2. Outage Experience and Tolerance

Respondents were asked targeted questions concerning outages to characterize their experiences and tolerance for such events. Respondent 1 experienced two short outages in the 12 months from the time of the interview, lasting between less than 1 minute and up to 4 hours. Both events were perceived as disruptive. Respondents 2 and 3 reported no outages in the last 12 months and expressed satisfaction with their current levels of electric reliability.

Across respondents, tolerance for outages declined with duration. Respondent 1 showed a higher tolerance of outages, with outages up to 8 hours being acceptable as long as they were infrequent (up to once per

month). For the other two respondents, short outages up to 5 minutes were acceptable if they occurred once in six months, whereas they showed lower tolerance for outages lasting longer than 2 hours. Table 20 summarizes the respondents' outage tolerance.

Table 20. Outage tolerance of the respondents.

Outage duration	Respondent 1	Respondent 2	Respondent 3
≤5 minutes	Once per week	Once every 6 months	Once every 6 months
2 hours	Once per month	Once every 6 months	Once per year
8 hours	Once per month	Unacceptable	Once per year
24 hours	Once every 5 years	Unacceptable	Once per year

5.3. Operational and Financial Impacts

Respondents were also asked to consider the operational and financial impacts of outages. Reported outage costs varied substantially, ranging from several thousand dollars for short events to hundreds of thousands of dollars for full-day interruptions. All respondents indicated minimal disruption and negligible costs for short outages lasting less than 5 minutes.

For Respondent 1, outages exceeding 1 hour were highly disruptive, primarily affecting staff productivity. A 1-hour outage was estimated to halt operations and reduce service capacity for nearly 5 hours.

Respondent 2 noted that outages longer than 1 hour were highly disruptive and would require compensating guests for the outage period, with total costs depending on occupancy levels at the time. During 24-hour outages, the inability to heat buildings could lead to frozen pipes, burst pipes, and the need for temporary heating, each representing a significant expense. The respondent also reported an incident in which a voltage fluctuation caused the loss of a telephone system worth approximately \$250,000. Following this event, surge protection technology was installed on all sensitive equipment.

Respondent 3 reported that momentary or 1-hour outages would have little operational impact. Outages lasting 8 hours or more would also be manageable if backup generators functioned as expected. However, generator failure during an extended outage would cause severe disruption, with estimated losses around \$300,000 (range: \$150,000–\$500,000) and particularly high interruption costs (\$500,000) during the peak processing season (April to early May). The respondents' estimated outage costs are summarized in Table 21.

Table 21. Estimated outage costs (2025\$).

Outage duration	Respondent 1	Respondent 2	Respondent 3
≤5 minutes	0	100	0
1 hour	10,000	2,500	0
8 hours	10,000	10,000	300,000
24 hours	20,000	50,000	300,000
3 days	-	150,000	-

Respondent 1 indicated that advance notice could reduce outage-related disruptions by nearly 90%. By contrast, the other two respondents did not identify any significant benefit from prior notification.

5.4. VoLL Calculations

The VoLL was estimated for the three respondents. First, electricity sales data for GVEA in 2024 (U.S. Energy Information Administration, 2025) were used to estimate the average commercial electricity consumption. The estimated average consumption was then used to calculate the unserved energy for different outage durations, with each reported outage cost divided by the corresponding unserved energy to determine the VoLL in \$/MWh.

While this approach provides a representative estimate for the GVEA service area, this regional consumption profile differs significantly from the Railbelt average. The Railbelt, comprising four major utilities (CEA, MEA, HEA, and GVEA), has significantly higher aggregate and per customer commercial electricity usage, driven primarily by the Anchorage economic centers served by CEA. This region hosts a more diverse and energy-intensive mix of C&I activity compared to the Interior. As a result, the average commercial consumption of the Railbelt is estimated to be over three times that of GVEA. Consequently, VoLL estimates based solely on GVEA data are expected to be higher than those derived from a Railbelt-wide dataset. The low average usage in C&I organizations in the GVEA service area (0.002 MWh/hour, equivalent to 0.05 MWh/day, 1.42 MWh/month, and 17.23 MWh/year), combined with moderate per-outage event costs, produced extremely high VoLLs.

Table 22. Calculated respondent VoLL (2024\$/MWh).

Outage duration	Respondent 1	Respondent 2	Respondent 3
≤5 minutes	0	596,259	0
1 hour	4,966,841	1,241,710	0
8 hours	620,855	620,855	18,625,655
24 hours	413,903	1,034,759	6,208,552
3 days	-	1,034,759	-

Table 22 presents the calculated VoLLs for the survey respondents.⁶ The VoLL estimates varied widely across respondents, reflecting clear sectoral differences. Respondent 1, an office-based service business, reported extremely high VoLL for short outages due to its low energy intensity and strong dependence on uninterrupted operations. By comparison, the hospitality business (Respondent 2) exhibited moderate VoLLs for shorter durations, consistent with steady power use and limited tolerance for interruptions. Respondent 2 also reported very high VoLLs for longer outages (more than 24 hours) due to loss of critical building systems and infrastructure. Respondent 3 (agricultural processing business) reported low VoLLs for short outages but very high VoLLs for longer duration outages (more than 8 hours), driven by high restart and process-related costs. Respondents 2 and 3 reported higher interruption costs for outages during peak seasons.

Across respondents, VoLL generally declined as the outage duration increased, because total outage costs did not grow proportionally to the energy not supplied. This pattern is consistent with findings from other jurisdictions reviewed in this report, such as ERCOT, New Zealand, Australia, and the nationally

⁶ The VoLL estimates, initially in 2025 dollars, were adjusted to 2024 dollars using the Consumer Price Index (U.S. Bureau of Labor Statistics, 2025a) to ensure consistency with the values reported for other jurisdictions. The CPI for 2025 was calculated as the average of the reported values from January through August—the most recent data available at the time of analysis.

representative studies by LBNL, where short interruptions tend to carry disproportionately high per-unit costs.

Although based on a very small sample, these results shed light on the structure and sensitivity of VoLL estimates in the Alaska context. They reveal how outage duration, sectoral characteristics, and operational dependencies can influence outage costs, and underscore the need for ongoing data collection to refine sector-specific VoLLs and understand mitigation behaviors.

6. VoLL Estimation Pathways

Developing credible, Alaska-specific estimates of VoLL requires methods that balance rigor, practicality, and data availability. Three methodological pathways are available to estimate VoLL for the Alaska Railbelt, each suited to different timeframes and levels of data maturity:

1. An analytical approach that uses the ICE 2.0 model and Railbelt data.
2. A hybrid approach that integrates ICE 2.0 modeling with targeted field testing to validate assumptions under local conditions.
3. A survey-based approach that directly measures customers' stated WTP to avoid outages.

6.1. Methodological Pathways

6.1.1. ICE Approach

The ICE 2.0 model uses econometric relationships derived from customer interruption surveys across 24 U.S. service territories. The model estimates outage costs as a function of the outage duration, customer class, regional income, and industrial composition. When combined with local Railbelt data—such as customer class load shares, regional economic indicators, and key customer characteristics—the ICE model can estimate outage costs for each customer class and outage duration without requiring new survey data. This approach is transparent, reproducible, and low-cost. However, because ICE reflects national averages from temperate climates and interconnected systems, its parameters must be stress-tested for Alaska's conditions, and results should be treated as provisional until validated with local evidence.

6.1.2. Hybrid Approach: ICE Baseline with Field Testing

The hybrid approach combines the analytical efficiency of ICE 2.0 with focused, small-scale field testing to validate or refine model assumptions under Alaska's unique conditions. ICE outputs provide preliminary VoLL "priors" by customer class and outage duration, which are then validated through targeted surveys with small samples. These field test surveys would not use fully representative samples of the Railbelt; they would focus on segments where Alaska is most likely to diverge from national patterns, such as short winter outages, heating and water dependence, and small commercial customers lacking backup power. The method could produce calibrated, Railbelt-specific VoLLs at a moderate cost. The ICE model could be used to obtain interim results, with field validation conducted at a later stage.

6.1.3. Survey Approach

This approach directly measures customers' WTP to avoid outages through surveys that present hypothetical outage scenarios varying in duration, timing, and prior notice. It captures behavioral and contextual factors such as backup generation use, heating dependence, and seasonal sensitivity by collecting primary data from residential and business customers. Representative sampling, typically stratified by customer class, region, and demographic characteristics, ensures that the results reflect the full diversity of the Railbelt. Because it derives directly from stated customer preferences, this approach provides the most empirically grounded and defensible VoLL estimates for planning and regulatory use, though it requires significant time and resources.

6.2. Decision Matrix for VoLL Estimation

Table 23 summarizes the key characteristics of the three pathways for VoLL estimation in Alaska and some trade-offs among them. The matrix evaluates each approach against set criteria including accuracy, technical complexity, and cost, providing a comprehensive basis for determining which method best suits the Railbelt’s short- and long-term requirements. The implementation time and cost were estimated by ACEP based on workload, salary, and budget projections; stakeholder confidence was estimated for key stakeholders (utilities and regulatory commissions) based on the VoLL literature and ACEP topic expertise.

Table 23. Comparative decision matrix for VoLL estimation.

	ICE approach	Hybrid approach: ICE + field testing	Survey approach
Description	Uses the LBNL ICE 2.0 econometric model with Railbelt data to estimate outage costs by duration and class.	Combines ICE-based modeling with targeted field testing to validate and adjust model assumptions under Alaska conditions.	Directly measures customers’ WTP to avoid outages through surveys across the Railbelt.
Data requirements	Existing Railbelt data (class load shares, regional economic indicators, customer characteristics) available from utilities, regional and state agencies, and EIA.	Existing Railbelt data; new data collected through surveys that target key regions and customer segments for model validation.	Utility-provided billing or contact data for sampling; new survey data from residential and business customers.
Accuracy and relevance	Moderate accuracy. Not representative due to ICE assumptions and estimates based on temperate U.S. regions.	High accuracy for targeted factors via local field validation. Does not use a representative sample.	Highest accuracy, with statistical significance. Fully representative of Alaskan customer behaviors and outage experiences.
Technical complexity	Low. Uses published ICE functions and local data integration.	Moderate. Requires analytical modeling plus small-scale survey design and synthesis.	High. Requires survey design, econometric modeling, and quality assurance.
Advantages	Fast, transparent, low-cost. Builds analytical consistency and a data framework.	Balances accuracy and feasibility through local data validation. High transparency.	Fully captures regional variation. High transparency and stakeholder confidence.
Limitations	Not representative or locally validated, may omit Alaska-specific drivers. Limited stakeholder confidence.	Field survey samples are small and non-representative. Moderate stakeholder confidence.	Time- and resource-intensive. Requires survey infrastructure and data sharing agreements with utilities.
Implementation time	6 months	8 months	12 months
Cost	\$75,000	\$200,000	\$300,000
Recommended use	Interim inputs for immediate modeling.	Short- and medium-term planning and analysis.	Long-term regulatory and planning applications.

These approaches can be adopted individually for targeted modeling and planning purposes. The ICE approach is suitable for obtaining interim VoLL estimates. It relies on existing tools (ICE 2.0 model) and available data (Railbelt customer characteristics, regional economic data), making it a low-resource, low-cost option for early VoLL adoption in Alaska. Such VoLL estimates may serve as provisional inputs for preliminary transmission planning, such as integrated resource planning, until more refined values become available in the future.

The hybrid approach offers VoLLs suitable for short- and medium-term planning. It combines ICE modeling with field testing to refine VoLL estimates based on local conditions. This option has moderate technical complexity and costs, as it combines existing tools and data with targeted field validation. These VoLL estimates can be used for interim benchmarking in transmission planning efforts.

The survey approach is a comprehensive option for developing accurate VoLL estimates based on ground realities. It captures local preferences and regional patterns, including customers' WTP to avoid outages and usage trends across utilities, although surveys can be very resource-intensive and require attention to detail to avoid collecting biased or low-quality data. Such VoLL estimates are suitable for long-term transmission planning efforts such as cost-benefit analysis, and reliability standard setting.

The three approaches can also be adopted sequentially to build a credible range of Alaska-specific VoLLs over time. The ICE 2.0 model provides a transparent baseline for immediate use; the hybrid approach calibrates these results with select Alaska data, providing more robust VoLL estimates. The survey approach can then deliver definitive, representative VoLLs once large-scale data collection is feasible.

7. Conclusions and Recommendations

This report was produced by the Alaska Center for Energy and Power as part of the Value of Lost Load (VoLL) project, which aims to develop Alaska-specific VoLL estimates to inform Railbelt reliability planning and investment decisions. Phase 1 focused on establishing a methodological foundation for VoLL estimation; Phase 2 will operationalize these findings by implementing the recommended VoLL estimation approaches. Developing credible, Alaska-specific VoLL estimates will enable more informed, transparent, and regionally grounded resource and reliability planning across the Railbelt.

7.1. Main Findings and Implications

The literature review indicates that VoLL is a foundational economic metric for assessing the cost of power interruptions and guiding investments in reliability. Nationally and internationally, a variety of methodologies have been developed to capture outage costs under different grid and economic conditions. Researchers widely agree that VoLL is not a universal constant; the local context, economic structure, climate, grid configuration, and customer characteristics all influence how customers perceive and respond to outages.

Six studies were reviewed in detail. (1) The Lawrence Berkeley National Lab’s ICE 2.0 study presents nationally representative, survey-based econometric equations that estimate outage costs across durations and customer classes for 24 service territories. (2) The Electric Reliability Council of Texas estimated VoLL first for different customer classes and outage scenarios using the ICE 1.0 model and then for the entire system using a large customer survey. (3) Midcontinent Independent System Operator adapted LBNL’s framework to its market context to estimate VoLL. (4) The Australian Energy Market Operator updated Australia’s value of customer reliability (the estimated value customers place on a reliable electricity supply) using large-scale, representative stated-preference surveying. (5) Transpower New Zealand used contingent valuation and choice modeling to derive point-of-supply VoLLs. (6) Baik et al. (2023) assessed long-outage costs for islanded and remote communities in Alaska and the South Pacific, providing valuable insights for the Railbelt.

For Alaska’s Railbelt, the need for regional VoLL adaptation is strong. The Railbelt operates under distinctive environmental, operational, and system conditions that shape how customers experience outages and value reliability. Long, cold winters and extended hours of darkness create strong dependence on electricity for heating, water, and communications. Harsh weather, permafrost, and complex fuel logistics can delay power restoration and constrain backup generation options. Alaska’s seasonal, resource-based economy—anchored in oil and gas, mining, tourism, and fisheries—adds further vulnerability, as brief outages can disrupt time-critical operations for commercial and industrial (C&I) organizations. These conditions underscore that while national-average models like ICE 2.0 provide a useful starting point, they must be adjusted or validated to reflect Alaska’s unique conditions.

Preliminary surveys with three Fairbanks C&I customers were used to obtain Alaska-specific VoLL estimates. The office-based services firm showed very high VoLL for short outages due to its reliance on continuous operations; the hospitality business showed moderate VoLL for short outages but very high costs for extended ones due to building systems failure; and the agricultural processing business showed low VoLL for short outages but very high values for long-duration events due to system restart and process losses. Consistent with national studies, per-MWh VoLL generally declined with outage length, except when infrastructure damage increased costs. Advance notice could reduce outage costs substantially (nearly 90%) for the office-based firm, whereas the other two businesses did not identify significant benefits from early notification. These preliminary results indicate strong variation in outage tolerance and cost sensitivity

across sectors in Alaska, underscoring the need for larger, regionally stratified surveys to produce representative VoLL estimates.

Based on the literature review and pilot surveys, three methodological pathways for Alaska-specific VoLL estimation were identified. The **ICE approach** is a low-cost, short-term analytical option that uses the ICE 2.0 model developed by the Lawrence Berkeley National Laboratory and existing Railbelt data. This approach offers interim VoLL estimates suitable for early modeling. The **hybrid approach** validates and calibrates the ICE 2.0 model results through targeted field testing in Alaska. This approach offers field-validated VoLL estimates suitable for short- to medium-term planning. The **survey approach** directly measures customers' willingness to pay (WTP) to avoid outages through comprehensive surveys stratified by customer class and region. This approach offers highly accurate, representative, and statistically significant VoLLs suitable for long-term planning in Alaska.

7.2. Recommendations for the RRC

A tiered dual approach is recommended to obtain useful VoLL estimates while balancing timeliness, cost-effectiveness, and methodological rigor. The RRC should begin with the **ICE approach**, which uses the ICE 2.0 model and existing reliability and economic data to generate transparent, interim VoLL estimates suitable for integrated resource planning and cost-of-unserved-energy studies. This approach can also help establish shared data systems and analytical consistency among utilities. Once key data systems and institutional capacity are in place, the **survey approach** should be gradually implemented to develop definitive, statistically representative VoLL estimates for long-term regulatory and planning applications. The survey results should be used for validating and calibrating the ICE results to reflect customer preferences and local conditions, particularly where Alaska diverges most from national patterns.

The suggested stepwise approach ensures that short-term decisions are informed by credible, Alaska-specific values while steadily improving the precision and representativeness of future VoLL estimates through field surveys. By integrating analytical efforts with survey data, the RRC can establish a transparent, defensible framework for valuing reliability that evolves with the region's data, organizational capacity, and policy needs.

Based on RRC needs and Alaska ground realities, two reference metrics are recommended: (1) a VoLL weighted by system load share and (2) a VoLL weighted by the customer classes most likely to be curtailed first under contingency or underfrequency load shedding events. VoLL estimates should be reviewed and updated every five years—or sooner if major demographic, technological, or reliability changes occur—to maintain their relevance and credibility.

Appendix A: Sources

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Appendix B: Supplementary Information

B1. New Zealand VoLL Estimates

Table B1. New Zealand VoLLs for residential, primary, industrial, and commercial customers (2024\$/MWh).

	Season and day of week	10 minutes	1 hour	5 hours	8 hours
Residential	Summer, weekday	-	2,683	3,044	2,562
	Winter, weekday	7,530	5,162	2,710	2,135
	Shoulder, weekday	-	3,960	2,737	2,222
	Summer, weekend	-	2,906	3,296	2,774
	Winter, weekend	8,068	5,532	2,903	2,287
	Shoulder, weekend	-	4,363	3,016	2,448
Primary, small	Summer, weekday	184,727	32,968	7,019	4,814
	Winter, weekday	183,758	32,861	7,008	4,818
	Shoulder, weekday	261,161	46,702	9,960	6,848
	Summer, weekend	209,831	37,515	7,998	5,498
	Winter, weekend	211,444	37,883	8,092	5,576
	Shoulder, weekend	303,041	54,294	11,598	7,991
Industrial, small	Summer, weekday	138,612	30,436	7,826	5,616
	Winter, weekday	127,388	27,971	7,193	5,161
	Shoulder, weekday	153,999	33,825	8,700	6,243
	Summer, weekend	131,885	30,536	8,136	5,930
	Winter, weekend	122,882	28,451	7,580	5,525
	Shoulder, weekend	149,760	34,689	9,245	6,739
Commercial, small	Summer, weekday	219,927	37,637	9,306	6,454
	Winter, weekday	175,364	30,018	7,435	5,160
	Shoulder, weekday	202,431	34,656	8,592	5,965
	Summer, weekend	241,471	41,392	10,353	7,215
	Winter, weekend	195,097	33,451	8,383	5,846
	Shoulder, weekend	227,032	38,933	9,767	6,814
Primary, large	Summer, weekday	88,358	16,125	4,159	2,737
	Winter, weekday	102,447	18,554	4,699	3,082
	Shoulder, weekday	132,231	24,021	6,127	4,025
	Summer, weekend	94,543	17,389	4,567	3,016
	Winter, weekend	112,016	20,419	5,252	3,455
	Shoulder, weekend	145,342	26,588	6,896	4,544

Industrial, large	Summer, weekday	45,944	10,072	3,154	2,154
	Winter, weekday	35,080	7,691	2,408	1,645
	Shoulder, weekday	66,616	14,415	4,448	3,031
	Summer, weekend	23,670	6,762	2,682	1,890
	Winter, weekend	18,323	5,234	2,076	1,463
	Shoulder, weekend	37,475	10,197	3,905	2,740
Commercial, large	Summer, weekday	-	16,569	11,981	6,579
	Winter, weekday	12,456	19,779	10,162	5,701
	Shoulder, weekday	-	10,075	9,435	5,118
	Summer, weekend	-	-	6,105	2,756
	Winter, weekend	-	-	6,303	3,170
	Shoulder, weekend	-	-	4,363	1,799

B2. Methodology for Tables 9 and 12

Transpower’s final VoLL figures (Transpower, 2018) incorporate PwC survey results, confidential results from Advisian interviews with large customers, and the demand composition across over 60 points of supply (PoS). Since Advisian’s results are not publicly available and PoS-weighted averages are not relevant metrics for this report, we used PwC’s customer class VoLLs (PwC, 2018) for cross-jurisdictional comparison. This ensures consistency across customer groups, although it may understate values for very large industrial users.

PwC (2018) provides VoLL estimates by sector (primary, commercial, and industrial) and size (small and large). For each size and sector, VoLL is reported by day of the week (weekday versus weekend) and season (summer, winter, and shoulder) for various outage durations. We adjusted these VoLLs from 2018 to 2024 New Zealand dollars using New Zealand Consumer Price Index data from the U.S. Bureau of Labor Statistics (2025b). Next, we obtained a single VoLL for each outage duration and sector by computing the time-weighted VoLL assuming that (i) weekends and weekdays respectively occur two and five days out of a seven-day period, and (ii) summer, winter, and shoulder respectively occur over 3, 3, and 6 months in a year.

To facilitate cross-jurisdictional comparison, we harmonized the PwC customer categories into residential, small commercial and industrial (C&I), and large C&I. The small C&I category is the average of small primary, small commercial, and small industrial, while the large C&I category is the average of large primary, large commercial, and large industrial. Lacking load share ratios, these averages were not weighted. The single VoLLs obtained for each group were converted to 2024 US dollars using the 2024 average exchange rate of 0.605 USD to 1 NZD (Exchange Rates, 2025).

B3. National and Alaska Outage Data

Table B2 reports the average customer-weighted outage metrics for national and Alaska Railbelt utilities for 2023 with and without a major event (U.S. Energy Information Administration, 2025). The national values are reported according to IEEE standards. The Alaska values for no major event include only MEA and HEA data reported according to IEEE standards, while the major event values include data from all

four Railbelt utilities (MEA, HEA, and GVEA report under IEEE standard; CEA reports under a different standard).

Table B2. Average customer-weighted outage metrics for 2023.

Area	Event scenario	SAIDI^a	SAIFI^b	CAIDI^c
National	No major event	123.9	1.0	121.3
Alaska Railbelt	No major event	369.1	2.4	151.1
National	With major event	366.6	1.348	271.8
Alaska Railbelt	With major event	394.4	2.6	144.9

^a System Average Interruption Duration Index, i.e., the minutes of non-momentary electric interruptions per year experienced by the average customer.

^b System Average Interruption Frequency Index, i.e., the number of non-momentary electric interruptions per year experienced by the average customer.

^c Customer Average Interruption Duration Index, i.e., the average number of minutes it takes to restore non-momentary electric interruptions.