THE COST OF WILDLIFE-CAUSED POWER OUTAGES TO CALIFORNIA'S ECONOMY

FINAL REPORT

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1. Overview

Wildlife-caused power outages are a persistent challenge for California's electricity industry and its regulators. Despite more than two decades of mitigation efforts, wildlife interactions with powerlines still account for as much as 10-25% of all power outages, in addition to killing or maiming endangered raptors and many other animals.[1] Yet the financial burden that these incidents place on the state's economy is poorly understood.

Anecdotal evidence indicates that wildlife interactions with power lines can be costly. A recent fire in Santa Clarita triggered by a hawk colliding with a power line prompted the evacuation of 1,600 homes and charred more than 5,700 acres.[2] Earlier this year, the Los Angeles International Airport experienced three power outages attributed to birds within 10 days, delaying flights and threatening airport security.[3] Separately, the California Condor Recovery Team reports that 9 of the 144 condors released into the wild since 1992 have died from electrocution. Based on the program's cumulative spending of nearly $40 million to date, this loss alone has cost taxpayers $2 million.[4]

These incidents may not be entirely preventable. But an electric utility's inaction can invite severe penalty in direct fines or mandated installation of preventative measures. The Migratory Bird Treaty Act (MBTA), the Bald and Golden Eagle Protection Act, and the Endangered Species Act entail that utilities are potentially liable for inadequately prevented

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[1] These data points were provided by Ms. Spiegel of CEC based on her 2001 personal communication with the staff of with PG&E (25%) and SCE (10%). Wind power is another cause of avian deaths. This problem has received much attention because it currently limits the growth of this renewable energy source in certain areas. A separate PIER-funded investigation examines this matter exclusively; see http://www.energy.ca.gov/pier/energy/project_fact_sheets/500-01-019.html for more information.

[2] Reuters News Service, July 19, 2004

[3] "The bird apparently managed to ground the line, which re-energized moments later, the department said in a statement. But despite the immediate restoration of the power supply, the effect on the tower lasted longer" (Associated Press, April 12, 2004).

"takings" of protected wildlife.[5] In 1994, Pacific Gas and Electric (PG&E) thwarted ensuing litigation through a monetary settlement with the US Fish and Wildlife Service (USFWS). This in turn spurred the growth of avian programs at each major California utility. Yet the costs and benefits of these programs have not been fully assessed.

Determining if a problem can be cost-effectively addressed requires knowing both the costs and benefits of various mitigation strategies. A mitigation program is said to be cost-effective if its costs of implementation are less than its benefits. This cost-benefit approach to program design is well established in the economic evaluation of demand-side-management (DSM) and energy-efficiency programs (Orans, Woo and Horii, 1994).

Without accounting for the value of birds saved, casual inference suggests potentially large benefits because the annual, statewide costs of all power outages and power-quality disturbances may total tens of billions of dollars for customers (Lineweber and McNulty, 2001). However, an outage-related loss of this magnitude due to wildlife collisions and electrocutions is questionable because (1) commercially available measures (e.g., onsite backup generation and uninterrupted power systems) offer a relatively affordable way to mitigate these losses, and (2) most wildlife-caused outages affect customers with relatively low outage costs.

The California Energy Commission (CEC) sponsors ongoing research on the cost of installing mitigation measures, their mitigation effects,[6] and the ensuing benefits. As part of this research program, the CEC hired E3 in May 2004 to assess the current statewide costs of the problem.

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[4] These figures are based on the total number of birds raised in the program, which includes some that have remained in captivity http://www.newscientist.com/news/news.jsp?id=ns99992137.

[5] According to the US Department of Agriculture (USDOA), "The MBTA is a strict liability law which means that the U.S. Fish and Wildlife Service (USFWS) only has to show that the birds were killed by the activities of an individual or business. It does not require the USFWS to prove that there was intent to kill or take a bird, only that a bird was killed or taken." (USDOA, p.32)

Albeit the data limitations described below, it is possible to make a preliminary estimate of the state's costs of wildlife-caused outages. Major California utilities catalog the various causes of sustained outages in their annual reliability reporting, document their service restoration costs, and have performed customer value-of-service (VOS) studies; we present this information in Section 3. We apply the approach in Section 2 to these publicly available data to develop our range of cost estimates in Section 4. We conclude in Section 5 that the annual estimated cost of wildlife-caused outages to the state of California ranges from $32M to $316M, thus informing various stakeholders (e.g., government agencies, regulators, electric utilities, and environmentalists) about the monetary size of the problem and the potential benefits of mitigation. We then specify the data that could help narrow the cost range and suggest how to implement a cost-effective mitigation program.

2. Approach

2.1 Description

Our approach is straightforward: the total cost of wildlife-caused outages is simply the sum of the individual costs triggered by such outages. Hence, we identify these costs, evaluate the available data, and sum the components to total cost. The cost components include:

(1) Customer costs of a sustained outage (defined as lasting more than five minutes). These vary by outage attributes and by customer characteristics. The primary data sources are the VOS studies done by SCE and PG&E; see Section 3.

[6] Techniques for assessing and mitigating wildlife-caused outages have been developing since the early 1980's; however, monitoring and prevention methods continue to evolve, with varying degree of success (EPRI, 2003).

(2) Customer costs of momentary outages and power quality disturbances. While such reliability problems have the potential to cause significant financial losses for certain customers, "[v]ery little information is available in the public domain regarding the costs of power quality problems" (Lawton, *et al*., 2003b, p.3). Though we find limited information on momentary outage costs in PG&E's VOS studies, we do not know the annual number of such outages that are wildlife-caused. Hence, we do not include this component in our calculation.

(3) Utility costs of service restoration. These are the costs of equipment repair after an outage. We include only the costs of above-ground corrective maintenance, which are available from the general rate case filings from PG&E and SCE, prorated by the proportion of outages that are caused by wildlife.[7]

(4) Societal value beyond customer and utility costs. Difficult to quantify, this is the value of wildlife to society. Various studies have produced a wide range of values for individual endangered species (White, 1996), rendering a reasonable valuation difficult.[8] Even if we had a precise value of each animal, we still do not know how many animals of each species are killed due to wildlife-power line interactions. Accordingly, our present computation intentionally excludes this value. This exclusion does not diminish the usefulness of our results for two reasons. First, if a mitigation program can be justified under the zero-value assumption, it is necessarily cost-effective. Second, should a program be found not cost-effective under the zero-value assumption, one could readily determine how much the affected wildlife must be worth in order to justify the program's implementation. If the

[7] A utility also incurs lost sales during an outage, but the effect is small and therefore omitted. Lost sales would be computed as the energy unserved times the difference between the retail rate and the cost of delivery.
[8] Government penalties stipulated in the MBTA and related protection acts are designed to deter takings and are not necessarily reflective of social value.

required worth is at the low end of published value range, the program is almost surely cost-effective.

Hence, our cost estimation is the sum of (1) and (3) because of the lack of data on (2) and (4). Since it excludes (2) and (4), it is a conservative method.

2.2 Assumption of an affected customer

When estimating customer costs due to a sustained outage, it is necessary to assume an affected customer because VOS estimates vary by customer characteristics. To develop this assumption, consider how these outages occur: a bird or other animal inadvertently contacts an energized power line or associated conductive equipment. This event causes either a brief power quality disruption or induces a short circuit. If a short circuit occurs, local equipment may automatically reset the circuit, resulting in a momentary outage that lasts less than five minutes. However, if the automatic systems cannot resolve the problem or if critical equipment is damaged, a sustained outage occurs, requiring service restoration by a utility repair team.

Sustained outages are characterized not just by cause—automobiles, fallen trees, strong winds, and general equipment failure are other common outage causes in addition to wildlife—but also by duration and the number of affected customers per outage. California utilities annually report two service reliability metrics:

- System Average Interruption Duration Index (SAIDI) measures the average interruption duration per customer of sustained outages in a given year (e.g., 100 minutes per year).

- System Average Interruption Frequency Index (SAIFI) measures the average number of customer interruptions experienced by all customers due to sustained outage events (e.g., 2.2 outages per year).

Both metrics are reported at the system level, without detailed reference to outage causes. Because VOS data suitable for our calculation of sustained outage costs is expressed in cost per kWh unserved, we estimate the wildlife-caused portion of unserved energy based on SAIDI using the method detailed in Appendix A.

We assume in our base case that the principal affected customer is a household. This assumption recognizes that wildlife randomly interacts with the above-ground electricity system, of which the distribution level contains the vast majority of conductive hardware. Since 88% of California's 13.5 million electricity customers are residential,[9] and these customers are served at the distribution voltage, we infer that residential customers are most widely affected by wildlife-caused outages.

Our alternative assumption of an affected customer is a "system average" customer. This assumption is necessary because commercial, industrial, and agricultural (i.e., non-residential) customers are also affected by wildlife-caused outages. We construct this "system average" affected customer from the weighted average of customer sales data for each customer class. This customer has a higher outage cost than a residential customer, primarily because non-residential outage costs are higher than residential outage costs.

[9] CEC 2001 report on electric retail sales: http://www.energy.ca.gov/electricity/utility_sales.html

3. Customer Outage Costs

The annual customer outage cost equals (a) the total unserved energy (UE in kWh) per year times (b) the unit outage cost ($/kWh unserved) (Forte, *et al*. 1995). Since the computation of (a) is mechanical (see Section 4 and Appendix A), below we focus on the topic of customer VOS.

3.1 Value of service and customer outage cost

Extant literature indicates that customer outage cost estimates are diverse (Munasinghe, Woo and Chao, 1988; Woo and Pupp, 1992; Caves, Herriges and Windle, 1990; Eto *et al*, 2001; Lineweber and McNulty, 2001; Overdomain, 2002; Lawton, *et al*., 2003a, 2003b). They vary by (a) outage characteristics (e.g., time-of-day, duration and season); (b) attributes of affected customers (e.g., residential vs. non-residential customers); (c) estimation method (e.g., analysis of outage cost survey data vs. estimation of market demand for reliability); and (d) data source (e.g., survey- vs. market-based data sample). To rationalize our use of the VOS estimates published by PG&E and SCE, this section reviews the outage cost estimation literature.

A VOS estimate indicates how much an electricity consumer values a particular level of reliability. It reflects the usefulness and/or necessity of electricity to the consumer. It is the net benefit of electricity consumption, equal to the gross benefit, less the cost of procuring that consumption (Woo and Pupp, 1992). If there were a market for reliability, electricity consumers would buy varying degrees of it to achieve their desired tradeoff between cost and reliability (Woo, 1990). In this case, the market price of reliability would allow a direct inference of VOS.

But because transmission and distribution outages are random events, they cannot be priced in this way. As a result, VOS is often approximated by an estimate of the customer's outage cost.

An outage cost estimate can be *ex ante* (before an outage occurs) or *ex post* (after an outage occurs). An *ex ante* outage cost refers to the loss an electricity consumer may incur due to an increase in the likelihood of an outage in the future. An example of an *ex ante* outage cost estimate is the amount of bill savings required to make a customer indifferent between the service reliability under the standard tariff and the one under a curtailable service rate option (Hartman, Doane and Woo, 1991; Caves, Herriges, and Windle,1992). An *ex post* outage cost refers to what the consumer suffers from an actual outage, like those caused by wildlife's interaction with electrical supply equipment. The *ex ante* estimate and the *ex post* estimate converge when the occurrence of an outage becomes certain. Since we are currently interested in the economic loss due to outages assumed to have caused by wildlife, we use *ex post* estimates in this study.

3.2 Diversity in customer outage cost

Extant literature explains the diversity in customer outage cost estimates as follows:

A. Outage attributes

A winter outage imposes a higher cost per kWh unserved on residential customers than a summer outage with the same duration and time-of-day of occurrence. However, commercial and industrial customer outage costs do not have a systematic seasonal pattern. Outages with an advance notice result in lower customer costs. A long outage likely imposes a lower cost per kWh unserved than a short one because the initial cost associated with an outage incidence is spread over more kWh unserved when the outage duration lengthens.

B. Customer characteristics

Residential customers tend to have a substantially lower cost per kWh unserved than non-residential customers. While an electrical outage in the home may inconvenience the resident, the same outage will likely impart a far greater financial damage to a non-residential customer due to idle labor and machines, equipment damage, missing production that cannot be made up, …, etc. Customers in an area with frequent outages likely have a lower per kWh cost than those in an area with infrequent outages because the former are experienced and better prepared to cope with service disruption. Backup generation ownership reveals that the owner places a high value on reliability and therefore is willing to pay for the cost of buying and operating backup generation to reduce the cost of an actual outage.

C. Estimation methods and data sources

A common VOS estimation method is to analyze survey data.[10] The analysis may range from simple descriptive statistics such as the average cost per outage (PG&E, 2000) to sophisticated econometric modeling (SCE, 1999; Hartman, Doane and Woo, 1991; Lawton *et al*, 2003b). A customer outage cost survey typically elicits responses regarding one or more of the following metrics:

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[10] As noted in Woo and Pupp (1992), the other methods are: (a) proxies (e.g., GDP per kWh consumption and per kWh cost of owning and operating a backup generator), (b) estimation of customer preference of reliability using (1) market data on customer subscription to curtailable service (Caves, Herriges and Windle, 1992) or (2) market data on customer ownership of backup generator (Matsukawa and Fujii, 1994), (c) estimation of loss of producer profit using market data on electricity consumption (Goldfeld-Nir and Tishler, 1994); and (d) estimation of loss of consumer surplus inferred from the area under a demand curve (Sanghvi, 1983). Given sufficient variation in service reliability, as in a cross-sectional data sample of customers in different areas of a utility service territory, one may infer customer outage costs via demand estimation using billing data and area-specific outage information (Woo, 1994; Woo and Lo, 1993).

(a) Willingness-to-pay (WTP) for backup generation to avoid an outage;

(b) Direct costs (DC) triggered by an outage (e.g., cost of spoiled food and inconvenience incurred by a household; cost of lost sales, idle labor, equipment damage suffered by a business firm), net of any cost savings due to the outage (e.g., bill savings due to electricity not consumed and wage savings due to labor sent home); and

(c) Willingness-to-accept (WTA) a bill decrease to tolerate an outage.

After controlling for differences in outage characteristics and customer attributes, responses made in a given survey produce WTP estimates that are lower than DC estimates, which in turn are less than WTA estimates.[11] The disparity between WTP and WTA estimates is attributable to strategic responses by survey respondents,[12] status quo bias due to extreme risk aversion (Hartman, Doane and Woo, 1991), and electricity reliability not being an "ordinary market good" (Horowitz and McConnell, 2002). Absent consensus on which type of estimate can best provide the "true" value of an outage cost estimate, Section 4 describes how we apply the three types of estimates: WTP, DC, and WTA.[13]

[11] However, this relationship among WTP, DC and WTA estimates may not necessarily hold when comparing estimates from two or more survey data samples.
[12] For instance, a respondent reports in a low WTP but a high WTA if he/she thinks the numbers will affect ratemaking by the electricity utility.
[13] This is notwithstanding that "the WTP estimates have been generally accepted as providing a more accurate assessment of the value of service reliability" (p. 39, Lawton *et al*., 2003b).

3.3 Customer outage cost estimates

A. Residential customer outage costs

Based on SCE (1999) and PG&E (2000) and Woo and Pupp (1992), Table 1 reports the estimated cost per kWh unserved for residential customers in California.[14] This table presents this VOS data in 2004 dollars using the Consumer Price Index (CPI) published by California Department of Finance; the original study values can be found in Table A.3 in Appendix A. Table 1 indicates that the WTP estimates from SCE and PG&E lie between $1.40 to $3.8/kWh unserved, the WTA estimates from SCE lie between $2.90 to $9.70/kWh unserved, and the DC estimates from PG&E lie between $5 to $9.40/kWh unserved. An initial inference from Table 1 is that the lower bound of the residential outage cost range should exceed $1/kWh unserved and the upper bound should be around $9.70/kWh unserved.[15]

[14] We decide not to rely on estimates in other studies (e.g., Lawton, *et al*., 2003a, 2003b; Eto *et al*, 2001; Overdomain, 2002) because they are not specific to California or are not suitably expressed in $/kWh unserved.
[15] The following table compares the average costs (not adjusted for inflation) per outage for four outage types, thus providing a final check of the reasonableness of this range.

Footnote Table 1: Comparison of the estimates in $ per outage event.

Outage type	Lawton et al (p.46, 2003b)	SCE (p. 60, 1999)		PG&E (p.13, 2000)	Woo and Pupp (p.116, 1992)	
	WTP	WTP	WTA	DC	WTP	DC
Summer afternoon: 1-hour	2.9	4.7	9.9	4.4	1.85	4.1
Summer afternoon: 8-hour	7.2	8.2	20.1	N.A.	N.A.	N.A.
Winter afternoon: 1- hour	3.3	N.A.	N.A.	N.A.	3.33	12.1
Winter afternoon: 8-hour	8.3	8.3	22.4	N.A.	N.A.	N.A.

Table 1: Residential customer outage cost in 2004$/kWh unserved, except for momentary outages.					
Outage type	SCE estimates based on SCE (1999, Exhibit 1999)		PG&E estimates based on PG&E (2000, p.22)	PG&E estimates based on Woo, and Pupp (1992, Table 2)	
	Willingness-to-pay (WTP)	Willingness-to-accept (WTA)	Direct cost (DC)	Willingness-to-pay (WTP)	Direct cost (DC)
Summer weekday afternoon: 1-hour	N.A.	N.A.	$5.10	$3.80	$8.50
Summer weekday evening: 1-hour	$4.60	$9.70	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	$1.50	$3.10	$5.00	$2.00	$7.40
Summer weekend afternoon: 4-hour	$1.40	$2.90	N.A.	N.A.	N.A.
Summer weekday morning: 8-hour	$1.60	$3.80	N.A.	N.A.	N.A.
Summer weekday afternoon: 12-hour	N.A.	N.A.	N.A.	$1.50	$6.60
Winter weekday afternoon: 4-hour	N.A.	N.A.	$7.20	$2.30	$9.40
Winter weekday afternoon: 8-hour	$1.60	$4.40	N.A.	N.A.	N.A.
Winter weekday morning: 12-hour	N.A.	N.A.	N.A.	$1.60	$7.20

B. Non-residential customer outage costs

Based on SCE (1999) and PG&E (2000) outage cost studies, Table 2 reports the estimated costs of per kWh unserved for non-residential customers in California. This table again employs the CPIs published by California Department of Finance to adjust all original estimates, which can be found in Table A.4 in Appendix A, to 2004 dollars. Note that only PG&E provides VOS data for agricultural customers, which likely reflects that Northern California has more agricultural customers than Southern California.

Table 2: Non-residential customer outage cost in 2004$/kWh unserved.							
Outage type	SCE estimates based on SCE (1999, Exhibit 5.5a)				PG&E estimates based on PG&E (2000, p.22)		
	Commercial / Industrial willingness-to-pay (WTP)	Commercial / Industrial direct cost (DC)			Commercial direct cost (DC)	Industrial direct cost (DC)	Agricultural direct cost (DC)
		Loss product	Idle input	Total			
Summer weekday afternoon: 1-hour	$10.00	$158.90	$90.00	$248.90	$68.20	$24.80	$11.50
Summer weekday evening: 1-hour	$9.60	$308.50	$110.20	$418.70	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	N.A.	N.A.	N.A.	N.A.	$40.60	$12.70	$11.70
Summer weekday: 12-hour	$3.00	$75.20	$41.80	$116.90	N.A.	N.A.	N.A.
Winter weekday afternoon: 4-hour	$15.90	$114.90	$60.90	$175.80	$51.90	$16.00	N.A.

Table 2 indicates that the commercial/industrial (C/I) WTP estimates for SCE lie between $3 and $15.90/kWh unserved. The C/I DC estimates for SCE are high, as indicated by (a) loss product cost: $75.20 to $308.50/kWh unserved; (b) idle input cost: $41.80 to $110.20/kWh unserved; and (c) total cost (= loss product cost + idle input cost): $116.90 to $418.70/kWh. These estimates greatly exceed those reported in the literature, most of which are less than $30/kWh unserved (e.g., Woo and Pupp, 1992, Table 3; Caves, Herriges and Windle, 1990, Figures 3 and 4).[16] This large difference is likely due to the way that SCE (1999) estimates the unserved energy per outage.[17]

[16] Eto *et al* (2001) and Overdomain (2002) only report the $/kWh unserved estimates from a 1992 study sponsored by Duke Power. Lawton *et al* (2003a, 2003b) do not contain estimates in $/kWh unserved.
[17] The following table compares the average DC (not adjusted for inflation) per outage for a summer 1-hour outage. This table shows that SCE's high estimated cost per kWh unserved (= average cost per outage / average unserved energy per outage) is likely due to its low unserved energy estimates which are "[b]ased on the average customer 1995 load information for SCE's C&I customers with 0-1,000 kW peak demand" (SCE, 1999, p. 69, footnote 32). To see this point, consider the definition of a $/kWh unserved estimate: outage cost per event / unserved energy per event. Hence, even if the per event outage cost estimates from two studies are similar for an identical event, the $/kWh estimate in one study can be much higher if it uses a lower estimate of the per event unserved energy.

The DC estimates for PG&E are \$40.60 to \$68.20/kWh unserved for commercial customers, which are at the high-end of the estimates in the literature. The industrial estimates are \$12.70 to \$24.80/kWh unserved, and the agricultural estimates are \$11.50 to \$11.70/kWh unserved, in line with those in the literature.

4. Empirical implementation

4.1 Cases

Our empirical implementation begins with a description of alternative cases for which economic costs are computed. This is necessary for two reasons. First, the total unserved energy per year (UE) and customer VOS data depend on our assumption of the affected customer (residential vs. "system average"). Second, VOS estimates for an affected customer vary by estimation method and data source. Hence, we consider the following cases:

- ***Base case:*** All unserved energy is residential. The VOS value reflects an average residential VOS value based on WTP, DC, and WTA estimates.
- ***Low case:*** All unserved energy is residential. The VOS value is the average of WTP estimates.
- ***High case:*** An affected customer is a "system average" customer to recognize that some affected customers are non-residential customers. The system average UE is a sales-weighted average of the residential and non-residential UE. The system average VOS is

Comparison of the estimates of \$ per outage event.

Outage type	Lawton et al (2003b, p.46)		SCE (1999, p. 66)		PG&E (2000, p.21)	
	Small C/I	Large C/I	Lost sales	Idle factor	Commercial	Industrial
Summer afternoon: 1-hour	1200	8200	1599	872	537	22400

a California sales-weighted average of the average residential VOS value and PG&E's DC estimate for non-residential customers.

4.2 Computation

The total cost of wildlife-caused outages to California is

$$TC \quad = \quad C + U$$

where C equals the statewide annual customer cost, and U equals the statewide annual utility cost. TC is calculated separately for the Base case, the Low case, and the High case and is summarized in Table 3. [18]

Because we only have utility-specific data, we must compute C and U on a utility basis and then sum these values for all California utilities to get a statewide value. Accordingly, the annual customer cost of wildlife-caused outages for the state is

$$C = \sum_{utility} UE_{utility} \times VOS_{utility}$$

In the equation above, UE is the total unserved energy per year for the given utility, and VOS is the per-kWh outage cost for the affected customer in the case under consideration. UE is the product of (a) SAIDI for each utility, (b) the total number of utility customers, (c) the percentage of all utility outage duration that is wildlife-caused, and (d) the average energy use per customer-outage hour (see Appendix A for a further description of these inputs). Both the values for UE and VOS will vary for each utility in each case.[19]

At the time of this report, we only have a value from PG&E for (c), the percent of total outage duration that is wildlife caused. We use this value for the remaining utilities in the state. Our method for computing TC, summarized in Table 3, allows for the inclusion of new utility-specific data as it becomes available.

The three major California IOUs—PG&E, SCE, and SDGE—serve 74% of all electricity sales in the state. Because the data necessary to compute C and U for the remaining California utilities ("Other Utilities" in Table 3) is unavailable, we generate this data from a sales weighted average of each value for the three IOUs. This method allows us to sum the values for C and U contributed by PG&E, SCE, SDGE, and Other Utilities to arrive at statewide values.

The utility cost U equals the product of (a) the utility's total corrective maintenance cost ($/year), and (b) the percent of all sustained outages that are caused by wildlife.[20] The supporting data and a further description of this calculation are given in Appendix A. Because we only have values for (a) and (b) from PG&E, we extrapolate values of (a) for SCE, SDG&E, and Other Utilities based on that utility's relative sales to PG&E, and use PG&E's value of (b) for all utilities.[21]

4.3 Results

[18] Suppose the cost of mitigation is K and the reduction in TC is ΔTC. The mitigation program is cost-effective if K < ΔTC. This shows that the estimation of TC under the status quo, which is what we are doing here, is a crucial step in formulating a cost-effective program.

[19] Here we present the general equation with unique VOS values for each utility. However, due to data constraints we use the same VOS values for each utility for a given case, as described in section 4.1.

[20] Note that to calculate U we employ the frequency of wildlife-caused sustained outages and not their duration.

[21] We do not expect the addition of their data to dramatically affect our final value for TC.

Table 3 summarizes the state's total cost due to wildlife-caused sustained outages. It shows that the cost of the Base case is about $34M/year, mainly driven by the utility cost of service restoration of $31M. The low customer cost of $3M/year is due to the total residential UE of only 669 MWh and the residential VOS of $4.45/kWh unserved. Since the customer cost is a small fraction of the total cost, reducing the VOS to $2.19/kWh as in the Low case only cuts the total cost by $1.5M. When we assume that the affected customer is the "system average", as in the High case, the customer cost increases substantially to $286M, resulting in a total cost of $316M.

Table 3: Cost of wildlife-caused outages California					
Utility	**PG&E**	**SCE**	**SDGE**	**Other Utilities**	**California Total**
Base Case					
Unserved Energy (MWh)	358	118	44	149	669
VOS ($/kWh)	4.45	4.45	4.45	4.45	
Customer Cost	$1,593,000	$526,000	$197,000	$661,000	$2,977,000
Utility Cost of Restoration	$9,959,000	$9,835,000	$1,907,000	$9,195,000	$30,896,000
Base Case Cost	$11,552,000	$10,361,000	$2,104,000	$9,856,000	**$33,873,000**
Low Case					
Unserved Energy (MWh)	358	118	44	149	669
VOS ($/kWh)	2.19	2.19	2.19	2.19	
Customer Cost	$785,000	$259,000	$97,000	$326,000	$1,467,000
Utility Cost of Restoration	$9,959,000	$9,835,000	$1,907,000	$9,195,000	$30,896,000
Low Case Cost	$10,744,000	$10,094,000	$2,004,000	$9,521,000	**$32,363,000**
High Case					
Residential Unserved Energy (MWh)	358	118	44	149	669
Residential VOS ($/kWh)	4.45	4.45	4.45	4.45	
Residential Cost	$1,593,000	$526,000	$197,000	$661,000	$2,977,000
C/I/A Unserved Energy (MWh)	4,925	1,875	555	2,173	9,527
C/I/A VOS ($/kWh)	29.66	29.66	29.66	29.66	
C/I/A Cost	$146,085,000	$55,627,000	$16,458,000	$64,448,000	$282,618,000
Utility Cost of Restoration	$9,959,000	$9,835,000	$1,907,000	$9,195,000	$30,896,000
High Case Cost	$157,637,000	$65,988,000	$18,562,000	$74,304,000	**$316,491,000**

5. Conclusion

The results in Table 3 leads us to conclude that the total cost of wildlife-caused outages for California ranges from $32M to $316M, depending the on the assumptions of affected customers and their corresponding energy use and VOS estimates.

These calculations would be more theoretically comprehensive and empirically complete if we could include the costs of wildlife-caused power quality disturbances. But we do not expect this cost component to contribute substantially to the total cost. While power quality disturbances can drastically affect certain industrial customers, they typically have far less effect (e.g. a TV flicker) on residential customers, which constitute the majority of affected customers.

The precision of the $32M-$316M range could be improved with additional data that answers the following questions:

1) Which customers are typically affected by wildlife-caused outages? Knowing the distribution of affected customers by customer class would improve our calculation, as it would allow us to narrow the range of VOS data and the range of average energy use per customer-outage hour.
2) Which species are involved with each outage? Obtaining dependable, statewide data on the species that are typically involved with power outages would allow us to offer a rough estimate of the total value of lost wildlife, based on the per unit value estimates reported in the literature (e.g., White, 1996).
3) Where do these outages occur on the T&D system? This knowledge would allow us to more accurately assess utility costs of restoration, though this would also require a similar breakdown of utility repair expenditures.

Given that wildlife habitats are concentrated in certain locations and that the costs of a utility's preventative measures vary across their system, it is likely that integrating this data will reveal key 'hot spots' where wildlife-powerline interactions can be prevented most cost-effectively.

Electric utilities are best situated to collect this data, as they must address each outage as it occurs. Yet certain institutional barriers preclude the collection and/or public dissemination of it. First, an electric utility may not collect detailed and comprehensive information on wildlife-related outages. And if they are collecting this data, it may not be in their interest to publicize it in light of the threat of severe fines or regulatory mandates.

Fortunately, all involved parties would like to reduce these costly and undesirable interactions between wildlife and powerlines. A possible way to overcome the institutional barriers and misaligned incentives that currently hamper progress in this field would be to design a transparent and mutually beneficial implementation approach based on cost-effective mitigation. The critical next step is to integrate assessments of the area-specific costs of outages and their corresponding preventative measures. This information can then foster a joint-implementation process that will be acceptable to the utilities, their regulators, and other stakeholders.

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Appendix A: Computation details

Total unserved energy per year

A utility-specific total unserved energy per year is

$$UE = SAIDI \times N \times W \times D$$

where SAIDI = system average interruption duration index which measures the average interruption duration per customer in a year, N = total number of utility customers; W = percent of the utility's total outage duration that are wildlife caused, and D = average kWh consumption per hour of an affected customer (residential or "system average"). Table A.1 details the construction of each variable.

Table A.1: Variable construction and data sources for total unserved energy calculation

Variable	Construction	Source	Remarks
SAIDI = system average interruption duration index (minutes)	Not necessary because it is directly available	CPUC utility reliability reports published for 2002.	This is one of the common metrics used by the electricity industry to measure reliability. It excludes Major Events.
N = total number of utility customers	Not necessary because it is directly available	CEC report for 2001 (the most recent)	This number is easy to obtain and can be updated readily.
W = percent of the utility's total outage minutes that are wildlife caused	Not necessary because it is directly available	PG&E reliability reporting (see PG&E, 2003)	At the writing of this report, we were only able to obtain this data for PG&E, which we used for our calculations for SCE and SDGE.
D = average kWh consumption per hour for the affected customer	(Annual class sales MWh / Number of customers in the class) * (1000/8760)	CEC report for 2001 (the most recent)	Since wildlife-caused outages occur randomly, the kWh unserved per outage hour is estimated using average kWh consumed per hour.

Note: Publicly available data from utilities on outages and outage restoration indicates neither the species involved nor the location on T&D system.

	Table A.2: Variable calculation for each IOU	PG&E	SCE	SDGE	Other Utilities*	California Total	Calculation
1	SAIDI (outage minutes)	139	50	77	93.47		input
2	N (number of customer accounts)	4,756,159	4,448,024	1,242,735	3,011,130	13,458,047	input
3	W (% outage minutes due to wildlife)	4.4%	4.4%	4.4%	4.4%		input
4							
5	Number of Residential Customers	4,165,073	3,910,889	1,111,087	2,591,355	11,778,404	input
6	Number of C/I/A Customers	591,086	537,135	131,648	419,774	1,679,643	input
7							
8	Annual Residential Sales (MWh)	26,919,816	24,684,999	6,117,742	18,523,886	76,246,443	input
9	Annual C/I/A Sales (MWh)	52,521,773	53,768,625	9,094,549	41,449,003	156,833,950	input
10	Total Sales (MWh)	79,441,589	78,453,624	15,212,291	59,972,889	233,080,393	8+9
11							
12	D-Residential (average kW demand)	0.74	0.72	0.63	0.72		8/5*(1000/8760)
13	D-C/I/A (average kW demand)	10.14	11.43	7.89	10.53		9/6*(1000/8760)
14							
15	Residential UE (kWh)	358,214	118,243	44,222	148,677	669,356	1*(1/60)*2*3*12
16	C/I/A UE (kWh)	4,924,721	1,875,272	554,830	2,172,624	9,527,447	1*(1/60)*2*3*13

* - SAIDI, W, and D are created from the sales-weighted averge of the given figure from each IOU.

VOS Data

Here we present the original VOS data in annual dollar values that the given study offered.

Table A.3: Residential customer outage cost in \$/kWh unserved, except for momentary outages. "N.A." indicates that the estimate for a given outage type is "not available" because it is not in the study cited.					
Outage type	SCE (in 1999\$ per kWh unserved)[a]		PG&E (in 1993\$ per kWh unserved)[b]	PG&E (in 1989\$ per kWh unserved)[c]	
	Willingness-to-pay (WTP)	Willingness-to-accept (WTA)	Direct cost (DC)	Willingness-to-pay (WTP)	Direct cost (DC)
Summer weekday afternoon: 1-hour	N.A.	N.A.	3.97	2.46	5.51
Summer weekday evening: 1-hour	3.99	8.35	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	1.31	2.65	3.83	1.28	4.8
Summer weekend afternoon: 4-hour	1.22	2.52	N.A.	N.A.	N.A.
Summer weekday morning: 8-hour	1.35	3.31	N.A.	N.A.	N.A.
Summer weekday afternoon: 12-hour	N.A.	N.A.	N.A.	0.98	4.29
Winter weekday afternoon: 4-hour	N.A.	N.A.	5.57	1.48	6.08
Winter weekday afternoon: 8-hour	1.41	3.83	N.A.	N.A.	N.A.
Winter weekday morning: 12-hour	N.A.	N.A.	N.A.	1.04	4.67

Notes:

a. Source: p.61, Exhibit 4.7a, SCE (1999).

b. Source: p.22, PG&E (2000).

c. Source: p. 116, Table 2, Woo and Pupp (1992).

Table A.4: Non-residential customer outage cost in $/kWh unserved. "N.A." indicates that the estimate for a given outage type is "not available" because it is not in the study cited.							
Outage type	SCE (in 1999$ per kWh unserved)[a]				PG&E (in 1993$ per kWh unserved)[b]		
	Commercial / Industrial willingness-to-pay (WTP)	Commercial / Industrial direct cost (DC)			Commercial direct cost (DC)	Industrial direct cost (DC)	Agricultural direct cost (DC)
		Loss product	Idle input	Total			
Summer weekday afternoon: 1-hour	8.63	137	77.6	214.6	52.6	19.1	8.9
Summer weekday evening: 1-hour	8.27	266	95	361	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	N.A.	N.A.	N.A.	N.A.	31.3	9.8	9
Summer weekday: 12-hour	2.56	64.8	36	100.8	N.A.	N.A.	N.A.
Winter weekday afternoon: 4-hour	13.7	99.1	52.5	151.6	40	12.3	N.A.

Notes:
a. Source: p.69, Exhibit 5.5a, SCE (1999).
b. Source: p.22, PG&E (2000).

Utility Cost

Assuming that the costs of restoring a wildlife-caused outage are similar to that of other outages, we calculate each utility's cost of this type of service restoration as U = (Utility's Corrective Maintenance Expenditures) * (percent of total outages that are wildlife-caused). We then extrapolate the utility costs to the state level based on the utilities' annual kWh sales relative to the state's annual kWh sales. Again, at the time of this draft, we only have PG&E's data on utility maintenance expenses, which are categorized into (1) Preventative Maintenance and (2) Corrective Maintenance, which is subcategorized into Corrective Maintenance, an expense expenditure, and Emergency Response, a capital expenditure. Our computation of U is based on (2).

	Table A.5: Utility Costs of Corrective Maintainence						
		PG&E	**SCE***	**SDGE***	**Other Utilities***	**California Total**	Calculation
1	Expense	$28,830,000	$28,471,459	$5,520,664	$26,619,136	$89,441,260	input
2	Capital	$55,566,000	$54,874,961	$10,640,348	$51,304,852	$172,386,161	input
3	Percent of all Sustained Outages that are Wildlife-caused	11.8%	11.8%	11.8%	11.8%	11.8%	input
4	Cost of wildlife-caused outage repair	$9,958,728	$9,834,878	$1,906,999	$9,195,031	$30,895,636	1*2*3

* - These values are computed from PG&E values based on statewide sales ratios