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INTERROGATORY 1:

Reference(s): Exhibit 2B

It is noted that expected rate impacts to Intermediate and Large Users are running at or below projected CPI over the application period.[1] It is also noted that projects that significantly enhance reliability measures can have a profound effect on reduced outage costs to high usage customer operations. This is conveyed by a number of Toronto Hydro's largest customer class who were invited to write in to support THESL's DSP, particularly underlining concerns over the cost of reliability and power quality events.[2]

The PSE reliability Benchmarking Study commissioned by THESL generally indicates while THESL's SAIDI performance is generally less than half the benchmark, SAIFI performance is significantly worse. As such, capital programs that address duration (response time, sectionalizing response improvements, contingency enhancement etc) rather than frequency (generally age related replacements) would be more discretionary when comparing THESL's current and projected performance against benchmarks. A table from that report[3] is provided below to illustrate this. (Note the spike in SAIDI and SAIFI due to the Dec 2013 ice storm).

[1] EB-2014-0116 Exhibit 1A Tab 2 Schedule 1 Table 8
[2] EB-2014-0116 Appendix A to Exhibit 1B, Tab 2, Schedule 7
[3] EB-2014-0116 Exhibit 1B Tab 2 Schedule 5 Appendix B Page 126 of 582

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Table 15 Combined Sample: Econometric Reliability vs. Actual and Projected Reliability

Year	SAIDI (Econometric Benchmark)	SAIDI (THESL Value)	SAIDI (% Difference)	SAIFI (Econometric Benchmark)	SAIFI (THESL Value)	SAIFI (% Difference)
2005	124.13	104.89	-17%	0.77	2.01	+96%
2006	126.75	94.06	-30%	0.79	2.17	+101%
2007	129.43	117.00	-10%	0.80	2.27	+104%
2008	132.23	74.40	-58%	0.81	1.76	+78%
2009	134.30	174.17	+26%	0.81	1.86	+83%
2010	135.97	99.60	-31%	0.81	1.95	+88%
2011	148.96	85.80	-55%	0.82	1.62	+68%
2012	162.18	90.00	-59%	0.84	1.60	+64%
2013	166.50	1271.40	+203%	0.87	2.91	+121%
2014	169.34	71.40	-86%	0.87	1.58	+60%
2015	171.13	73.80	-84%	0.88	1.55	+57%
2016	172.81	70.20	-90%	0.89	1.44	+48%
2017	174.92	67.20	-96%	0.90	1.36	+42%
2018	177.04	64.80	-101%	0.91	1.27	+34%
2019	179.14	61.20	-107%	0.92	1.19	+26%

The same benchmarking study also indicated that "total *cost econometric benchmarking results indicate the following findings.*

1. The historical total cost levels of Toronto Hydro are below benchmark expectations at a 90% confidence level when using a dataset that includes both Ontario and U.S. utilities.

2. the projected total cost levels during the Custom IR period remain below the benchmark predictions, although they do converge towards benchmark expectations, and the "statistically below expectations" conclusion is no longer applicable at a 90% confidence level."[4]

[4] EB-2014-0116 Exhibit 1B Tab 2 Schedule 5 Appendix B Page 81 of 582

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For these reasons, constraints of time, and the fact most of the System Renewal Investment programs were deliberated at length during EB -2012-0064 System Renewal Investments was not review.

General

"Non-renewal programs are also expected to improve system and operational performance during storm events. For example, Feeder Automation (E7.3) is expected to significantly improve fault isolation, location and restoration on feeder trunks, simplifying restoration efforts during certain types of major storm events and freeing up resources for reactive repairs on lateral sections of feeders. Targeted, highvalue programs such as Contingency Enhancement (E7.1), Downtown Contingency (E7.7) and Design Enhancement (E7.2) are expected to improve system performance during storms by ensuring that operators and crews have full flexibility to transfer and restore load and by hardening vulnerable parts of the system with more optimal fusing arrangements and the installation of assets such as tree-proof overhead conductors"[5] All of these stated benefits improve SAIDI. They are primarily designed to facilitate rapid response after the event has occurred.

a) Please identify which Capital Investments have reliability as their primary or secondary drivers where that reliability improvement directly affects SIADI [sic]?
b) Figure 1 and Figure 4 Page 8 Section 2B-Original – SAIDI and SAIFI Projections of a Run to Failure Approach.
    a. Please provide comparison forecasts for each reliability metric for the proposed CIR without the impacts due to Feeder Automation (E7.3), Contingency

[5] EB-2014-0116 Exhibit 2B Section 00 Page 11 Lines 8-16

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Enhancement (E7.1), Downtown Contingency (E7.7) and Design Enhancement (E7.2)

b. Please identify the total man hour commitment for the total capital project program[6] in each of the application years.

RESPONSE:

a) The programs listed below feature reliability as their primary or secondary drivers in the DSP. (Please note that these are not the only DSP programs that are expected to have a direct impact on reliability.) Reliability can be improved or maintained in one of three ways: (1) decreasing the probability of an outage; (2) decreasing the number of customers an outage interrupts; or (3) decreasing the duration of an outage. All of these will ultimately directly affect SAIDI.

- Box Construction Conversion
- Contingency Enhancement
- Customer Owned Station Protection
- Design Enhancement
- Downtown Contingency
- Energy Storage Systems
- Facilities Management & Security
- Feeder Automation
- Fleet and Equipment Services
- Generation Projects Protection and Control

[6] EB-2014-0116 Exhibit 2A Tab 6 Schedule 2

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- Load Demand
- Local Demand Response
- Network Circuit Reconfiguration
- Overhead Infrastructure Relocation
- Overhead Momentary Reduction
- Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers
- Polymer SMD-20 Renewal
- Reactive Capital
- Rear Lot Conversion
- Stations Control and Monitoring
- Stations Expansion
- Stations Switchgear Renewal
- Underground Legacy Infrastructure

While all these programs have a positive impact on SAIDI, the benefits are rarely limited to duration and will generally improve SAIFI as well.

For a list of programs that Toronto Hydro expects will help reduce restoration times, please see the response to Interrogatory 2B-SIA-10.

b)

a. The following table provides reliability projections for the proposed CIR and a scenario with the four referenced programs excluded.

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		2015	2016	2017	2018	2019
SAIDI	CIR	1.23	1.17	1.12	1.08	1.02
	CIR Without Programs	1.28	1.27	1.26	1.26	1.25
SAIFI	CIR	1.55	1.44	1.36	1.27	1.19
	CIR Without Programs	1.61	1.56	1.53	1.49	1.45

Please note that, due to the nature of system level reliability projections (described in Exhibit 2B, Section D3), a comparison of the two scenarios above is not a precise depiction of the incremental reliability benefits of the isolated programs. Reliability projections at the system level rely on assumptions about interdependencies between various DSP programs. For example, some investments in the Feeder Automation program will depend on the execution of certain investments in various other programs to ensure that there is no loading or cable size limitations. As individual programs are removed or isolated from a system level review of reliability impacts, original modeling assumptions may no longer hold in specific situations, meaning that the scenarios may not be fully comparable on a one-to-one basis. These modeling limitations apply to the inverse analysis as well, i.e., executing only these four programs in isolation will not necessarily yield the same incremental system level SAIDI/SAIFI improvements presented in the table above. Despite these caveats, the table above illustrates in general terms the customer value that Toronto Hydro expects to realize via the proposed programs.

Toronto Hydro believes that further disaggregating this information into individual program-based projections would not provide a meaningful or accurate depiction of the benefits of these programs. Extracting the projected SAIDI/SAIFI benefits of a single investment program from the DSP requires

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modifying the underlying assumptions for other closely related or directly interdependent programs to the extent that the model may no longer accurately represent the remaining suite of programs.

Furthermore, Toronto Hydro notes that this type of program-by-program comparative analysis of reliability projections does not reflect Toronto Hydro's asset management decision making process. As explained in Exhibit 2B, Section D3, Toronto Hydro runs a comparison of its proposed plan versus a baseline "run-to-failure" approach to understand the overall system-level benefits of its proposed investments. However, this projection is an *output* of the long-term and short-term planning processes described in Section D3. This output is intended to help track system-level progress of the proposed capital expenditure plan over the course of plan execution, allowing Toronto Hydro to identify emerging issues or to reprioritize investments from year-to-year based on SAIDI/SAIDI trends versus projections.

For a complete discussion of Toronto Hydro's asset management process, including reliability projections and the role that they play in Toronto Hydro's planning process, please see Exhibit 2B, Section D.

b. A portion of the total capital program is externally contracted and is forecasted using total dollars based on specified contract costs as opposed to hours. As a result, it is not possible to provide the total man-hour commitment for the total capital program for each of the application years as this information is not tracked by Toronto Hydro through its planning process.

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INTERROGATORY 2:

Reference(s): Exhibit 2B, System Pressures Critical Issues: Climate Change

"*An AECOM-Toronto Hydro report entitled Future Impacts of Climate Change on Toronto Hydro's Distribution System (E8.8, Appendix A) concludes that weather and climate change can be expected to impact the reliability of the distribution system going forward, and that Toronto Hydro will be required to manage assets that may not have been designed for future climate conditions."*[1]

I think we can all agree with that statement however the extension of this critical issue to THESL's distribution system may be premature. Consider the following….

The Report goes on to states in the Section on Toronto Hydro Actions to Date – Further Work that,

"*However, better projections of the likely frequency and intensity of major storm events, freezing rain, and wind are required to better define the magnitude of the likely impacts on the distribution system;"*[2]

The AECOM report also states *"Toronto Hydro has taken the initial steps in its journey toward building a resilient network which supports the broader resilience of the City of Toronto. However, there are limitations in Toronto Hydro's current understanding of its potential network vulnerabilities in the face of climate change. Notably, much of the work to date* ***remains at a preliminary phase****, and further work is still required to*

[1] EB-2014-0116 Exhibit 2B Section 0.0 page 10
[2] EB-2014-0116 Exhibit 2B E8.8 Appendix A AECOM Report Page 32

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understand the impacts of a changing climate, including how the course of climate change will evolve, as well as developing, prioritizing, costing and financing the potential adaptation solutions to enhance the resilience of the electrical distribution system to climate change."[3] *(My emphasis)*

For its part THESL indicates that it will undertake engineering studies *"to focus specifically on identifying areas of the distribution system that are vulnerable to extreme weather and climate change …."*[4]

a) In light of the above please explain why any program drivers to improve the systems weather response and/or incremental expenditures made in advance of follow up studies are not premature?
b) Please identify any program or incremental capital that is being used to "harden" THESL's distribution System in response to the "Critical Issue of Climate Change" over the application period.

RESPONSE:

a) As stated in Exhibit 2B, Section 00, p. 11:

> During the 2015-2019 planning horizon, Toronto Hydro intends to conduct climate adaptation studies to assist with engineering analysis, informed decision-making and standards development for overhead and underground capital programs. These studies are expected to focus specifically on identifying areas of the distribution system that are vulnerable to extreme

[3] EB-2014-0116 Exhibit 2B E8.8 Appendix A AECOM Report Page 32
[4] EB-2014-0116 Exhibit 2B Section 0.0 page 11 Lines 19, 20 21

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weather and climate change, and include pilot projects for assessing study recommendations. These pilot projects are intended to help Toronto Hydro finalize climate adaptation solutions before programs are carried out at a system level.

Thus, contrary to the suggestion in the question, improving system weather response is not a program driver for the work proposed in Toronto Hydro's DSP.

b) None of Toronto Hydro's planned capital and maintenance programs are proposed to immediately address climate change. Below is a list of planned investments and maintenance activities with their program (or trigger) drivers that are likely to have the effect of improving system performance against extreme weather and climate change.

1) (E6.5) Overhead infrastructure Relocation program –Trigger Driver: Functional Obsolescence.
2) (E6.6) Rear Lot Conversion – Trigger Driver: Functional Obsolescence.
3) (E6.7) Box Construction Conversion – Trigger Driver: Functional Obsolescence.
4) (E7.3) Feeder Automation – Trigger Driver: System Efficiency
5) (E7.1) Contingency Enhancement Trigger Driver – Reliability
6) (E7.7) Downtown Contingency – Trigger Driver: Reliability
7) (E7.2) Design Enhancement (including Tree Proof Conductor) – Trigger Driver: Reliability
8) (5.) Vegetation Management (E4.A, Tab 2, Schedule 1, pages 26-34) – Trigger Driver: Reliability.

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INTERROGATORY 3:

Reference(s): **Exhibit 2B, Section E5.5 System Access Investments, Accommodating DG**

"*Toronto Hydro projects that 626MW of DG will connect to the distribution system by the end of 2019"*[1]

Has this forecast been endorsed by the OPA?

a) Please identify any THESL capital contributions required for the elimination of Transmission Constraints[2] for DG by Hydro One at the relevant TS's supplying THESL?

b) Will future DG connections be required to install proposed SCADA and monitoring equipment at their site at their cost as part of THESL connection requirements? If not, why not?

c) Will the "bus–tie reactor" "upgrades to address short circuit issues at Richview TS require any capital contribution from DG proponents? If not, why not? Does this project meet the DSC requirements Section 3.3.2 of the code to qualify as Renewable Enabling Improvements?

d) Where load generation ratios have increased beyond the one third rule does THESL plan to recover any anti- islanding protection modification costs from the existing DG's? If not, why not.

[1] EB-2014-0116 Exhibit 2B Section E 3.3.3 page 5
[2] EB-2014-0116 Exhibit 2B E3.3.2.1 – Transmission Constraints – page 5

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RESPONSE:

The OPA has endorsed the Renewable Energy Generation Investments Plan. The OPA comment letter as part of EB-2014-0116, Exhibit 2B, Section B, Appendix C, states: "The OPA has reviewed THESL's information for REG investments, and finds that THESL's Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date, as summarized by the following comparisons."

a) There are no capital contributions from Toronto Hydro for the elimination of Transmission Constraints for DG by Hydro One at the relevant TSs supplying Toronto Hydro's service area.

b) Future DG connections (both renewable and conventional) require SCADA and monitoring at customer sites. The costs associated with *renewable energy generation* SCADA and monitoring equipment will be included as part of Toronto Hydro's Generation Protection, Monitoring and Control program (Exhibit 2B, Section E5.5), consistent with the definition of *renewable enabling improvements* in Section 3.3.2 of the DSC. The costs associated with conventional (i.e., non-renewable) generation SCADA and monitoring equipment is borne by the generator.

c) Capital contributions from DG proponents will not be required. The project meets the requirements of Section 3.3.2 of the DSC.

d) Toronto Hydro does not plan to recover any anti-islanding protection modification costs from existing DGs. The conventional generation resources in these areas already have automated, remote trip features due to their larger nameplate capacity. Any costs associated with modifications to existing *renewable energy generation* will be

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included as part of Toronto Hydro's Generation Protection, Monitoring and Control program, consistent with Section 3.3.2 of the DSC.

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INTERROGATORY 4:

Reference(s): Exhibit 2B, Section E7.1 System Service Investments, Contingency Enhancement

a) Preferred Alternative (i)[1] – Please clarify if the do nothing option changes if reliability due to aging assets is addressed in other capex programs.

b) Please clarify the basis for expectations in frequency of major storms and impact to distribution system given the previous concerns regarding premature conclusions on the effect of climate change on the distribution system.

c) Please clarify whether contingency issues related to sufficient tie and sectionalizing, upgrading under-sized loop conductors and upgrading undersized trunk egress cable could be addressed independent of SCADA control. If so why is this option not considered?

d) What is the expected impact to SAIDI metrics from this program?

RESPONSE:

a) The alternatives contemplated in this program are not affected by asset renewal activities in other capital programs.

Mitigating asset failure risk involves mitigating both the probability of failure and the expected magnitude of impact of failure. The renewal of aging assets on distribution feeders lowers the probability of failure by replacing old or poor condition assets with new assets. However, lowering the probability of asset failure does not address the

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additional problem of sub-optimal configurations of existing feeders, and therefore does not address the relatively poor service that customers on these specific feeders are likely to experience in the event of an outage (regardless of outage cause). As explained in Toronto Hydro's DSP, the proposed capital expenditure plan for 2015-2019 includes a number of "beyond the asset" (Exhibit 2B, Section D3, page 9) programs like Contingency Enhancement that are intended to deal with critical system-wide issues and to take advantage of cost-effective opportunities to enhance customer value. Contingency Enhancement in particular is expected to enhance the value that customers on these feeders derive from both existing and renewed assets by ensuring that the overall magnitude of impact of outages is cost-effectively minimized. The value of these investments is significant regardless of the probability of failure on the feeder, as demonstrated by the significantly positive NPV for the first year of the proposed program (Exhibit 2B, Section E7.1, page 25).

e) An AECOM-Toronto Hydro report, "Future Impacts of Climate Change on Toronto Hydro's Distribution System" (Exhibit 2B, Section E8.8 Appendix A), forms the basis of Toronto Hydro's current expectations regarding the frequency of major storms and the potential impact of climate change on the distribution system. With respect to AMPCO's previous concerns regarding premature conclusions on the effect of climate change on the distribution system, please see Toronto Hydro's response to interrogatory 2B-AMPCO-2.

b) The contingency issues directly related to sufficient tie and sectionalizing points, upgrading under-sized loop conductors and upgrading undersized trunk egress cable could be addressed independent of SCADA control. However, because the

[1] EB-2014-0116 Exhibit 2B Section E7.1 Lines 4, 5

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incremental benefit of installing SCADA control at tie and sectionalizing points significantly outweighs the incremental cost, Toronto Hydro did not contemplate the option of installing non-SCADA-enabled switches in this program.

c) Toronto Hydro expects implementation of the Contingency Enhancement program to have a positive effect on SAIDI metrics. For further details, please see response to interrogatory 2B-AMPCO-1, part b.

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INTERROGATORY 5:

Reference(s): Exhibit 2B, E7.2 Design Enhancement

a) E7.2.1 – Preferred Alternatives[1] – Why is tree trimming not a costed option and instead dismissed out of hand as not customer value driven?

b) What is the impact on tree related outages due to the ice storm in 2013 on the outage rates and trending in Figure 5 and Figure 6 on page 15 Exhibit 2B Section E7.2

RESPONSE:

a) Tree trimming was not considered as a costed option in the Design Enhancement business case because it is not a feasible replacement for the proposed capital investments in the program. The feasibility of additional tree trimming is often limited by several factors such as tree species, growth patterns, impact to the health of the tree and, in cases of excessive trimming requirements, aesthetics. The proposed installation of tree-proof conductor should therefore be considered additional to Toronto Hydro's vegetation maintenance program.

b) Figure 6 on page 15 of Exhibit 2B, Section E7.2 displays total tree-related interruptions (combined momentary and sustained) from 2003-2013. Of the 2013 tree-related interruption statistics, 60% of CHI, 9% of CI, and 15% of outage frequency is attributed to tree-related outages during the ice storm in year 2013. The general trend of tree-related outage frequency is increasing regardless of ice storm impacts.

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Figure 5 on page 15 of Exhibit 2B, Section 7.2 displays frequencies of sustained trunk and lateral outages, specifically on the 27.6 kV voltage level, for all types of outages (not only tree-related outages). Of the 2013 interruption statistics, less than 1% of trunk outages and less than 1% of lateral outages is attributed to tree-related outages during the ice storm in year 2013. The general trend of sustained trunk outages is increasing regardless of ice storm impacts.

[1] EB-2014-0116 Exhibit 2B Section E7.2.1 page 3 Lines 6-12

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INTERROGATORY 6:

Reference(s): Exhibit 2B, Section E7.3 Feeder Automation

a) What is the expected impact to THESL SAIDI and SAIFI metrics following implementation of this program particularly with respect to SAIDI benchmark figures presented by the PSE Benchmarking study?[1]

b) Could you please provide figures on the percentage contribution of non asset related outages to the total figures for CI and CHI presented over the application years for both the Horseshoe and Downtown areas?

c) Please clarify the basis for expectations in frequency[2] of major storms and impact to distribution system given the previous concerns regarding premature conclusions on the effect of climate change on the distribution system.

d) As the feeder automation system mitigates impacts of defective equipment reducing the rate of asset replacements and to maintain a moderate pace of system renewal[3] can a paced execution strategy for the DSP still be attainable without this program without significantly impacting SAIFI and SAIDI?
(Typo in labelling preferred alternatives – Exhibit 2B E7.3.1 page 3 Line 10 is not an option, Line 4 then makes sense.

e) Will the feeder automation system address feeder restoration issues identified in the DG Section 5.5 related to net feeder loading on feeders[4] with a heavy ratio of load to DG capacity?

[1] EB-2014-0116 Exhibit 1A Tab 2 Schedule 1
[2] EB-2014-0116 Exhibit 2B E7.3 page 2 Lines 1,2
[3] EB-2014-0116 Exhibit 2B E7.3.3.1 Page 19 table 4
[4] EB-2014-0116 Exhibit 2B E5.5 Page 10 Lines 27-29, Page 11 Lines 1-5

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f) Please provide statistics related to accidents or near misses that would support inferred Safety improvement from the elimination of "risky" manual switching.[5]

RESPONSE:

a) Toronto Hydro expects implementation of the Feeder Automation program to have a positive impact on SAIDI and SAIFI metrics. For further details, please see Toronto Hydro's response to interrogatory 2B-AMPCO-1, part b.

b) The referenced document **s**peaks to the historical CI and CHI, not the values projected over the application years. The five-year historical average proportions of asset to non-asset CI is 41% asset related to 59% non-asset related. The five-year historical average proportions of asset to non-asset CHI is 45% asset related to 55% non-asset related.

c) Please see response to interrogatory 2B-AMPCO-4, part b.

d) Feeder Automation and a number of other System Service programs are important aspects of Toronto Hydro's efforts to execute a paced capital renewal program that delivers significant value-for-money during the CIR period and beyond. While a minimum level of sustained asset renewal is required to reduce the probability of outages across the system, Toronto Hydro's plan balances these needs with "beyond the asset" programs like Feeder Automation that reduce the risk of asset failure by significantly mitigating the magnitude of the expected impact of failure in a cost-effective manner. Therefore, while Toronto Hydro could theoretically deliver a

[5] EB-2014-0116 Exhibit 2B E7.3.3.1 Page 18 Table 3

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revised version of the paced strategy shown in the DSP without Feeder Automation, such a plan would be notably less cost-effective, prudent and balanced overall. With respect to system-wide reliability outcomes, it is reasonable to assume that, without Feeder Automation, Toronto Hydro would have to make less cost-effective investments to achieve the same improvements in reliability that are associated with the proposed DSP.

e) No, the Feeder Automation program will not address feeder restoration issues identified in Section E5.5 of the DSP. The Feeder Automation program relates to the coordinated sectionalizing of feeders to isolate faults. In contrast, the DG islanding risks highlighted in Section E5.5 (pages 21-23) are due to the ratio of DG capacity to load on a given feeder section. Theoretically, to the extent that feeder automation will create smaller feeder sections on existing feeders, the ratio of DG capacity to feeder section loading could increase, thereby *increasing* the need for control and monitoring at the DG site itself. Regardless, as demonstrated in Section E5.5, Toronto Hydro requires DG monitoring and control at all existing and future DG sites in order to continue accommodating the high level of DG penetration in a safe and efficient manner.

f) The following table represents the number of near misses or accidents related to manual switching. There have been a total of 32 incidents recorded since 2010: 21 near misses and 11 accidents.

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Incidents from Manual Switch Operation		
Year	Near Miss	Accident
2010	3	0
2011	4	1
2012	3	4
2013	10	1
2014	1	5

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INTERROGATORY 7:

Reference(s): Exhibit 2B, E7.4 Overhead Momentary Reduction

a) Please provide the root cause analysis identifying the cause of feeder interruptions impacted by this program.

RESPONSE:

As defined in Section E7.4.2 of the reference, a momentary interruption lasts less than one minute, meaning that there is no need for isolation or fault correction to restore power to customers. A feeder is typically not patrolled after it has experienced a momentary interruption unless the momentary interruption is preceded by multiple momentary interruptions in a short period of time. As a result, Toronto Hydro does not usually know the specific causes of momentary interruptions. In some cases, however, a specific cause is suspected based on conditions (such as weather or repeated equipment failures). The number of momentary interruptions captured in ITIS on a feeder is tracked and monitored for planning purposes and maintenance activities. As explained in the referenced section, this program will target areas experiencing a high frequency of momentary interruptions and where the capital work proposed is more prudent than increasing maintenance activities.

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INTERROGATORY 8:

Reference(s): Exhibit 2B, Section E7.7 Downtown Contingency

a) Has any mitigation activity taken place to address any of the Downtown Contingency Outages listed?[1] If so how is that accounted for in the estimation of improvement in reliability for this program?

RESPONSE:

a) Yes, Toronto Hydro has conducted mitigation activity to address the Downtown Contingency outages listed in Exhibit 2B, Section E7.7, page 11, Table 5. Examples of mitigation activities for the two most severe incidents are given below.

1) On January 15, 2009, Dufferin TS was completely shut down due to flooding caused by the HONI fire suppression system within the station. A total of 34,308 customers were impacted, with some customers were left without electricity for up to 24 hours. Since this incident, Dufferin TS has had upgrades to its fire suppression system, water containment, and removal systems, and monitoring systems to prevent recurrence.

2) On January 23, 2005, a similar incident of flooding occurred at Terauley station where 3,556 customers in Toronto downtown core were interrupted for ten hours. This flooding in the Terauley station basement was caused by a City water main

[1] EB-2014-0116 Exhibit 2B, Section E7.7, page 11, Table 5

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break. The City has repaired the break and Toronto Hydro has installed water barriers between the cable chambers in the street and the station.

Among other operational benefits, the Downtown Contingency program is expected to mitigate the impact of future low-probability, high-impact events similar in magnitude (but not necessarily similar in cause) to the events highlighted above. Projections of reliability improvements for non-renewal programs like this one depend primarily on historical reliability data. While some investments have been made to reduce the impacts if specific incidents were to recur, future contingency events of this magnitude remain a real possibility and the potential impacts of these events support the value of the Downtown Contingency program to customers (particularly in light of the reality that these interruptions can be due to factors beyond Toronto Hydro's control).

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INTERROGATORY 9:

Reference(s): Exhibit 2B, Section E7.8 Customer-Owned Station Protection

a) Please explain THESL's rationale for proceeding with Program E.7.8 – Customer Owned Substation Protection in light of Section 4.1.7 and 4.1.8 of the DSC that indicates that it is the customer responsibility for correction of adverse impacts to the Distribution System?

b) Please comment on the potential for THESL liability under the Audit Phase of the COSP program involving customer owned, operated and maintained equipment for unidentified deficiencies that end up failing.

c) *"The failure of customer-owned equipment resulted in approximately 17 interruptions per year."*[1] Was any corrective action ordered of the customers related to these incidents under Section 4.1.7 of the DSC. If not, why not?

d) *"Currently, 22% of the visited customer-owned substations in Horseshoe area were identified as being poorly maintained or past their useful life. These substations can create safety hazards for both the general public and Toronto Hydro employees*".[2] Where [sic] any safety hazards identified by THESL staff that required notice to ESA? If not, is it overstating the secondary driver of this program to include "public safety".

[1] EB-2014-0116 Exhibit 2B E7.8 page 3
[2] EB-2014-0116 Exhibit 2B E7.8 page 3

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

RESPONSE:

a) In accordance with the DSC, in the case where customer-owned equipment presents an issue, Toronto Hydro's practice is to advise the customer to upgrade their equipment to ensure compliance with the utility's standards at the customer's cost. The Customer-Owned Substation Protection program is designed to minimize existing reliability issues and protect Toronto Hydro customers from interruptions that would otherwise be caused by the failure of customer-owned equipment at a specific substation.

b) Under the Audit Phase, for the customer-owned, operated and maintained equipment, Toronto Hydro will not be liable for any unidentified deficiencies that end up failing. Customers are responsible for providing, inspecting, maintaining, repairing and replacing all customer-owned equipment and infrastructure to ensure that the reliability and safety of the distribution system is not compromised. (Please refer to section 1.7.5 Customer-Owned Equipment, Infrastructure, and Property in the Conditions of Service.)

c) In accordance with the DSC, Toronto Hydro has taken corrective action by issuing a Customer Advice Form ("CAF") to customers. A CAF is issued to notify customers of deficiencies and to direct the customer to correct deficiencies that arise on customer-owned equipment and assets.

d) Within the visited sample locations, Toronto Hydro has not encountered customer-owned substations that require immediate correction regarding public safety. If a safety hazard is discovered by Toronto Hydro staff, the utility will notify ESA of the identified safety hazard. Toronto Hydro takes the safety of the public and employees

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

seriously and seeks to address potential risks proactively. The utility's approach in this regard is demonstrated throughout its DSP, where a majority of programs feature Safety as a primary or secondary driver.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 10:

Reference(s): Exhibit 2B, E7.9 Stations Expansion

a) Please identify any capital contribution amounts anticipated to be received by THESL or paid to HONI as a result of the stations expansion program.

RESPONSE:

a) Toronto Hydro does not anticipate receiving any capital contributions as a result of the stations expansion program. A summary of estimated capital contributions to be paid to HONI based on current information is provided in the table below.

Description	Total Estimated Cost ($M)	Estimated Contribution to HONI ($M)
Copeland TS – Phase 1 (carry over)	192.9	0.0
New Transformer Station in Manby TS area	72.0	15.0
Expansion of Runnymede TS	33.0	33.0
Copeland TS - Phase 2	46.0	2.0
HONI T12 replacement and upgrade	0.5	0.5
Basin TS short circuit upgrades	2.0	1.5
Bathurst – New Feeder Positions	1.5	1.5

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

Note that the capital contribution amount is a subset of the Total Estimated Cost presented in the middle column. These estimates are subject to change as the projects progress, up until the time that a formal contract is executed between Toronto Hydro and HONI.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 11:

Reference(s): Exhibit 2B, E7.11 Energy Storage Systems

1) What are the environmental risks, if any, associated with each type of storage technology contemplated?
2) What is the anticipated cost of addressing the system benefits in a more conventional manner?
3) What is the level of risk associated with the technology and technical resources required?
4) Please clarify whether incremental land costs are included in the total project costs?
5) Where Power Quality problems are mitigated from the program is THESL currently meeting PQ standards in this area? If so will there be any capital contributions from PQ impacted customers who experience improvement of PQ beyond standard?
6) What assumptions where made with respect to reliability impacts to CI and CHI in the program cost analysis?

RESPONSE:

1) Toronto Hydro is not aware of any environmental risks associated with the normal operation of each type of storage technology contemplated.

2) The anticipated cost of addressing the system benefits in a more conventional manner vary, as each specific case is unique. When conventional approaches to address these issues are viable, Toronto Hydro utilizes them.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

3) Toronto Hydro expects there will be a reasonable level of risk associated with the technology and technical resources required. Toronto Hydro has experience working with and deploying different energy storage technologies. Please refer to Section E7.11.5.2 Program Risks for an explanation of program risks and mitigation options

4) In general, incremental land costs are included in the total project costs.

5) With respect to Toronto Hydro, there are currently no PQ standards in this area. Capital contributions from PQ impacted customers who experience improvement of PQ in this area are not anticipated as part of the Energy Storage Systems program.

6) No assumptions were made with respect to reliability impacts to CI and CHI in the program cost analysis.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 12:

Reference(s): Exhibit 2B, E6.20.1 System Renewal Investments Reactive Capital

a) Please provide the analysis that led to your forecast prediction for the number and cost of corrective work requests in the application years, particularly in light of the need to increase program dollars over the forecast years despite a substantial system renewal program over these same years.[1]

RESPONSE:

To arrive at the forecasted dollars for Reactive Capital, Toronto Hydro conducted and considered a number of analyses. The analyses were based on historical spending, the quantity and type of corrective work requests, asset failures and their associated reliability impacts, as shown in Exhibit 2B, Section E6.20, Figures 8-10 on pages 15-17 and considered the allocation of historical Reactive Capital Spending as shown in Exhibit 2B, Section E6.20, Table 8 on page 29. Emphasis was initially placed on forecasting the 2015 expenditure before determining 2016-2019 amounts. An example of one analysis that was conducted for determining the 2015 projection is a weighted average of expenditures between 2010 and 2013 as shown in the table below:

[1] EB-2014-0116 Exhibit 2B Section E6.20 Page 6 Table 3

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

($ millions)	2010	2011	2012	2013	2015 Forecast[3]
Total Expenditure	25.1	28.6	29.2	37.4	32.0
Adjusted Total Expenditure[1]	25.1	28.6	29.2	33.8	30.5
Escalated Adjusted Expenditure[2]	26.8	30.5	31.1	36.1	**32.5**[4]

[1] Adjusted to remove $3.5 million of expenditures associated with the 2013 Ice Storm.

[2] Escalated from year of dollars to 2015 dollars using an escalation factor of 1.3%.

[3] Forecast is calculated using a weighted average (i.e., Forecast = 40% of 2013 value + 30% of 2012 value + 20% of 2011 value + 10% of 2010 value).

[4] The final 2015 forecast for Reactive Capital is $31.9 million (Exhibit 2B, Section E6.20, page 28).

Based on the 2015 Forecasts that were established, years 2016 to 2019 were projected, with consideration given to the following facts (Exhibit 2B, Section 00, pages 6-18):

- 26% of assets are at the end of their useful lives with an additional 7% expected to reach end of life by 2020; and
- despite the proposed system renewal program, significant reductions in the overall age of assets on the system will not result until after the 2015-2019 period given that investments are being paced and that the proposed plan is for the system to reach "steady state" in 2037.

The projections are that between 2015 and 2019, corrective work requests and expenditures will increase by approximately 2% each year. Volatility is however expected from one year to the next, particularly for the number of corrective work requests (Exhibit 2B, Section E6.20, page 6) given the nature of the Reactive Capital Program.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 13:

Reference(s): Exhibit 2B, Section D3 FIM Model

a) Footnote Reference[1] – Please discuss THESL's interpretation of the OEB Decision and Order referenced in the footnote - "FIM Inputs may only come at significant cost."

b) Please itemize any changes or refinement to the FIM input and algorithm calculation of net benefit and net avoided risk cost from Not in Kind and Like for Life situations over that presented in the FIM model in EB-2012-0064.

c) Has THESL researched any new evidence since EB-2012-0064 related to the estimation of customer interruption costs used in the FIM model? If so please state the reference and applicability to the selection of THESL's CIC values within the FIM.

d) Please confirm the asset groups where the FIM model is used in the current application and note any changes in asset groups since EB-2012-0064.

RESPONSE:

a) Please see part c.

b) Toronto Hydro has refined the FIM inputs since the EB-2012-0064 application as follows:

- The age-based failure probability curve for DC battery systems was adjusted in response to battery failure data being collected and demonstrating that battery

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

failure occurs at an average age of approximately 10 years, as indicated in Section E6.19.3.2 of the Distribution System Plan (Exhibit 2B, Section E6.19, Page 11, Line 23).

- New structured and uniform nomenclature was introduced within the Avoided Risk Cost (ARC) and Cost of Ownership (COO) business case evaluation (BCE) results in order to enhance user-friendliness.
- Within the Cost of Ownership evaluation, Additional Quantifiable Benefits (AQB) and Maintenance Costs (MC) as defined within Section D3.3.2 of Toronto Hydro's Distribution System Plan (Exhibit 2B, Section D3, Page 29, Line 4) were formally introduced to provide further clarity and enhance user-friendliness of the business case evaluation (BCE) results.
- New underground switch asset subtypes were introduced to account for legacy switches such as Sachsenwerk Switch & Fuse Units and Submersible Five-way or Six-way Switches
- New underground cable subtype was introduced to account for leaking cables
- New underground transformer subtype was introduced to account for legacy Transclosure units
- New asset types were introduced within the FIM as identified in the response to Interrogatory 2B-AMPCO-13 part d.

c) Since the EB-2012-0064 application, Toronto Hydro has issued an RFP and determined the scope and estimated costs associated with the undertaking of a Toronto-specific Customer Interruption Cost ("CIC") valuation study. Toronto Hydro is currently awaiting rate approval from the Ontario Energy Board to continue

[1] EB-2014-0116 Exhibit 2B Section D3 Footnote 2 Page 14

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

and complete the study. Please refer to Section E8.8 of Toronto Hydro's Distribution System Plan (Exhibit 2B) for further details on the Program Support investment program, which includes the proposed CIC valuation study.

d) The asset groups where the FIM models are used in the current application include:

- Circuit Breaker
- Power Transformers
- Stations Switchgear
- Overhead Transformers
- Overhead Switches
- Poles
- Underground Switches
- Underground Transformers
- Underground Cables
- Network Units
- Network Vault – *New in this application*
- Stations DC Batteries – *New in this application*
- Cable Chambers – *New in this application*
- ATS & RPB Units – *New in this application*
- Stations Buildings – *New in this application*
- Remote Terminal Units (RTU) – *New in this application*

Those asset groups identified as "New in this application" above have been introduced since the EB-2012-0064 application.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 2B, Section D3, page 14

Preamble:

Customer Interruption Costs (CIC) values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro adopted $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. These values, which were discussed at length in Toronto Hydro's 2012-2014 rates application, are established through work with consultants as well as the analysis of results from reliability valuation studies.

a) Below (Table 1 – Customer interruption cost breakdown) is list of studies referred to in Toronto Hydro's 2012-2014 rates application (EB-2012-064 Tab 6F, Schedule 1-27). Please confirm if these studies are still relied on in representing the Event and Duration costs for CIC in this application?

Table 1 – Customer Interruption Cost Breakdown

	Study Name	Duration Cost ($/kVA)	Event Cost ($/kVA)	Reference	Page Number on PDF
A	Interruption Costs Netherlands	8.721	6.579	N/A	4
B	THESL	15	30	N/A	N/A

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

	Study Name	Duration Cost ($/kVA)	Event Cost ($/kVA)	Reference	Page Number on PDF
C	The Use of Customer Outage Cost Surveys in Policy Decision-Making	14.436	35.982	N/A	5
D	Consumer Expectations of DNOs and WTP for Improvements in Service	22.539	8.769	Table 29	35
E	Economic Valuation of Electrical Service Reliability	17.631	86.652	N/A	9
F	How to Estimate the Value of Service Reliability Improvements	50.94	42.93	Table 1	3

b) If yes, please provide a full copy of each of the Study reports. If no, please provide a list and copy of the studies used in determining THESL Duration and Event cost for this application.

c) Please confirm if THESL is aware of any other utilities that have derived customer interruption costs values for project evaluation purposes. If yes, please provide a list of these utilities?

d) Please provide customer interruption cost values derived by these other utilities and include supporting evidence.

e) Please confirm, the studies quoted in the table in part (b) use peak load as a proxy for the number of connected customers? If yes, please provide the supporting evidence. If no, please discuss the methodology used in the studies use and include supporting evidence.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

RESPONSE:

a) Toronto Hydro considered the studies listed in (Table 1 – Customer interruption cost breakdown, except for Row B – "THESL") in developing the Customer Interruption Costs (CICs) used in this application.

b) The requested studies are provided as Appendices to this Schedule:

- Appendix A: Interruption Costs Netherlands
- Appendix B: The Use of Customer Outage Cost Surveys in Policy Decision-Making
- Appendix C: Consumer Expectations of DNOs and WTP for Improvements in Service
- Appendix D: Economic Valuation of Electrical Service Reliability
- Appendix E: How to Estimate the Value of Service Reliability Improvements

c) Although THESL is aware that customer interruption costs values have been used by other utilities for various purposes, it cannot confirm those utilities' exact use, values, or methodologies.

d) See response to part c.

e) THESL cannot confirm whether or not the studies quoted in the table in part (b) used peak load as a proxy for the number of connected customers. The studies were only considered in determining the Event and Duration Cost on a per kVA basis used in this application.

Non-Residential Consumers

- Perceived actual interruption costs
- Base scenario: Interruption without warning on a Wednesday at 10:00 am near the end of January
- Other scenarios were also posed but are not included here

Non-Residential Consumers

Duration	Cost [£]		
	Commercial	Industrial	Large User
Momentary	11.47	1.2k	216k
1 min	11.74	1.5k	216k
20 min	49.12	2.9k	219k
1 hour	106.00	4.3k	233k
4 hour	345.00	7.6k	329k
8 hour	719.00	12.0k	413k
24 hour	1000.00	16.3k	581k

Non-Residential Consumers

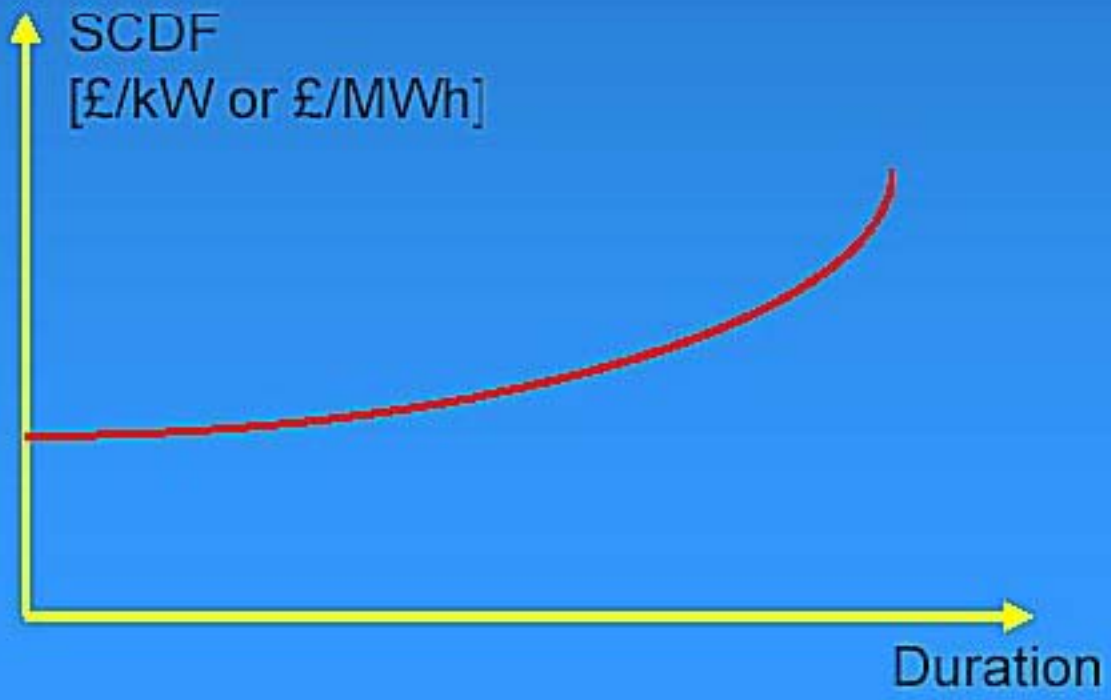
Duration	SCDF [£/MWh]		
	Commercial	Industrial	Large User
Momentary	0.46	3.02	1.07
1 min	0.48	3.13	1.07
20 min	1.64	6.32	1.09
1 hour	4.91	11.94	1.36
4 hour	18.13	32.59	1.52
8 hour	37.06	53.36	1.71
24 hour	47.58	67.10	2.39

Non-Residential Consumers

Duration	SCDF [£/KW]		
	Commercial	Industrial	Large User
Momentary	0.99	6.15	6.74
1 min	1.02	6.47	6.74
20 min	3.89	14.27	6.86
1 hour	10.65	25.26	7.18
4 hour	39.04	72.22	8.86
8 hour	78.65	120.11	9.71
24 hour	99.98	150.38	13.35

Sector Customer Damage Functions

- Give the average cost of an outage of a certain duration for a given sector



Application

- Given composition of load on a feeder
  - x MW residential, y MW commercial, z MW industrial
- Given fault statistics for this feeder
  - Fault rate and distribution of fault duration
- We can calculate the expected annual cost of outages on this feeder
- More accurate for residential and commercial than for industrial because there are more of them on a typical feeder

Value of Lost Load

Incident

Clip

Customer Outage Costs

Energy Not Supplied

?

VoLL = COC / ENS

Customer Outage Costs

- Depend on:
  - Number of outages
  - Duration of outage
  - Time of outage
  - Advance notice
  - Current activities
  - Prevailing weather conditions
- Have little direct connection to amount of energy not supplied
- Example:
  - International football match vs. drying the laundry

Value of Lost Load

- VoLL does not reflect and cannot reflect the value that consumers place on their supply of energy

- The fact that VoLL can be calculated does not justify its use

But I would really like to know VoLL…

- Should reflect as much as possible the factors that influence the cost of outages
  - Duration of outages
  - Difference between the various sectors
- Consider various outage durations r_i

$C_{Ly}(r_i)$ Customer interruption cost for an interruption of duration r_i for sector y normalised based on maximum demand

LF_y Load factor for sector y

$$VoLL_y(r_i) = \frac{C_{Ly}(r_i)}{LF_y \times r_i}$$

But I would really like to know VoLL…

$$VoLL(r_i) = \sum_y VoLL_y(r_i) \times k_y$$

Where k_y is the weighting factor for sector y

Weighting factors can be based on:

- Annual energy consumed in the sector
- Peak demand of the sector
- Number of consumers in the sector

$$VoLL = \sum_{r_i} VoLL(r_i) \times p(r_i)$$

Where $p(r_i)$ is the probability of an outage of duration r_i

Which VoLL do you want?

Considering interruptions of up to 24 hours:

Weighting	VoLL [£/kWh]
Energy	10.88
Number	2.68

Considering only interruptions of one hour:

Weighting	VoLL(1 hour) [£/kWh]
Energy	18.25
Number	2.64

Comments (1)

- Weighting based on numbers of consumers biases the value towards the VoLL for residential consumers
- Weighting based on energy makes much more sense than weighting based on numbers
- VoLL from UMIST study is thus much higher than the "official" value
- Good agreement with value from surveys in other countries
- Official value is apparently based on a Finnish survey from the 1970's, converted to £'s and adjusted for inflation

Comments (2)

- Using a cost/benefit analysis, it can be shown that a much higher VoLL than the "official" value must be used to justify the current level of reliability
- Values given reflect current expectations of reliability.
- Applicability to much higher or lower levels of reliability is questionable

Conclusions

- VoLL is a poor way to estimate the value of the security of the electricity supply
- More accurate techniques have been developed to determine the cost of outages to consumers
- These techniques require
  - A cost model
  - A probabilistic outage model
  - A load model
- Applied mostly to the development of strategies for distribution network enhancement

References

- CIGRE Task force 38.06.01, "Methods to Consider Interruption Costs in Power System Analysis", CIGRE Publication 191, August 2001.
- K.K. Kariuki, R.N. Allan, "Evaluation of Reliability Worth and Value of Lost Load", IEE Proc. -Gener. Transm. Distrib., Vol. 143, No. 2, March 1996, pp. 171-180.
- R.N. Allan, "VOLL - Fact or Fiction", IEE Power Engineering Journal, February 1995.
- "Impact Assessment of the 1977 New York City Blackout", H.C.P./T5103-01, Springfield, VA: National Technical Information Service, July 1978.

Toronto Hydro-Electric System Limited
EB-2014-0116
Interrogatory Responses
2B-AMPCO-14
Appendix B
Filed: 2014 Nov 5
(7 pages)

POLITECNICO DI MILANO

WORKSHOP

L'ANALISI DI IMPATTO DELLA REGOLAZIONE IN UNA AUTORITA' INDIPENDENTE DI REGOLAZIONE: L'ESPERIENZA DELL'AUTORITA' DELL'ENERGIA

UNIVERSITA' DEGLI STUDI DI MILANO
Milano, 18 maggio 2009

THE USE OF CUSTOMER OUTAGE COST SURVEYS IN POLICY DECISION-MAKING: THE ITALIAN EXPERIENCE IN REGULATING QUALITY OF ELECTRICITY SUPPLY

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Customer outage cost: a survey

Objectives

- Provide economic valuation of undelivered energy for two consumer categories: domestic and business
- Set financial incentive rates for the continuity of supply regulation

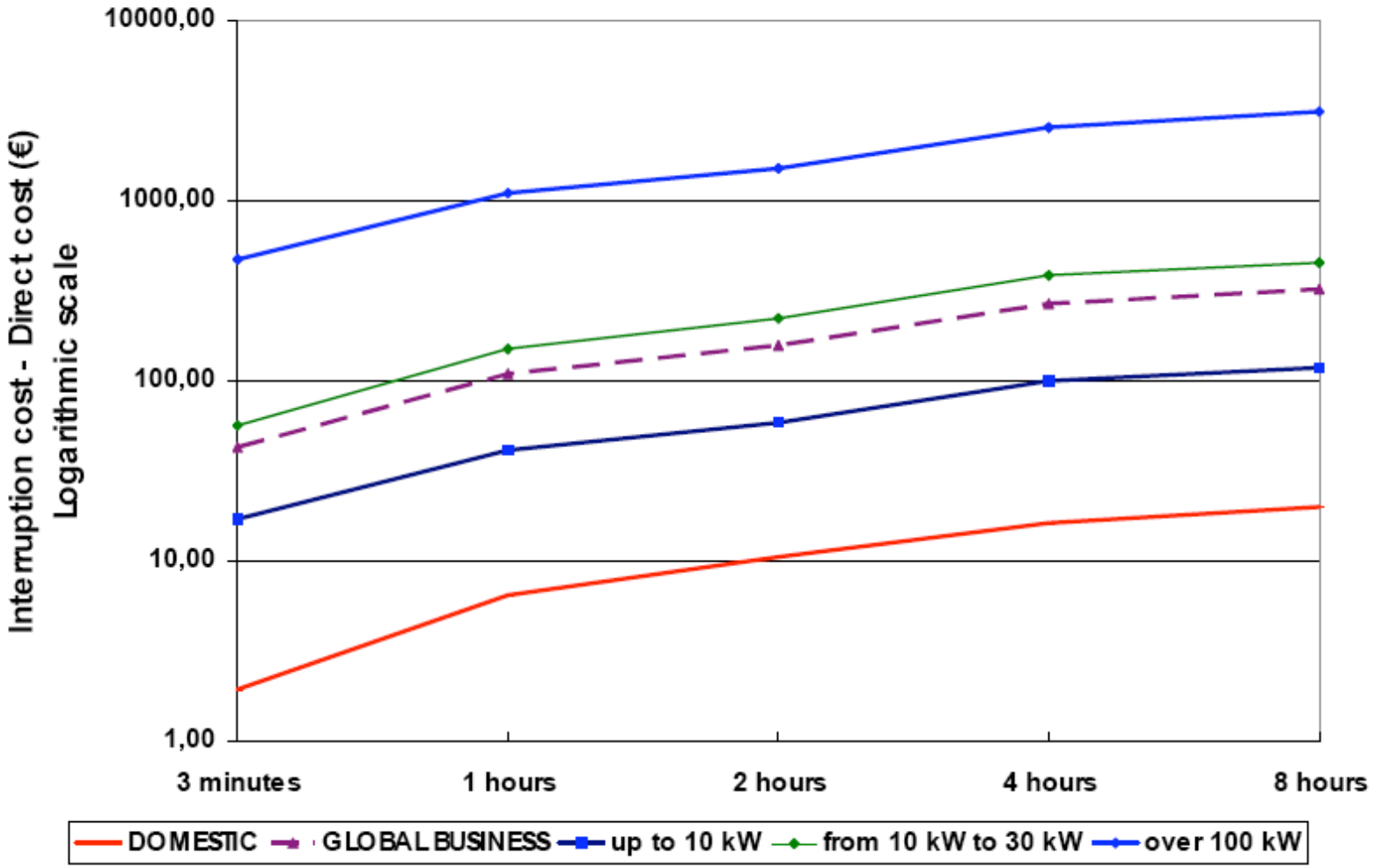
Methodology: contingent valuation method

- Valuation of economic damage ensuing from a hypothetical interruption scenario
  - Direct Cost
  - Willingness To Pay (WTP)
  - Willingness To Accept (WTA)
- Normalization on Energy Not Supplied

Sample design: fundamental variables

Variables	Domestic	Business
Number of interviews	1100 face to face	1500 face to face: 600 industrial sector, 900 commerce and services
Size of the company	n.a.	On the basis of number of employees, in 4 classes: 1-2, 3-9, 10-49, 50-499
Geographic areas	North West, North East, Centre, South, and Islands	
Size of locality	Metropolitan areas, Large, Medium, Small locality	

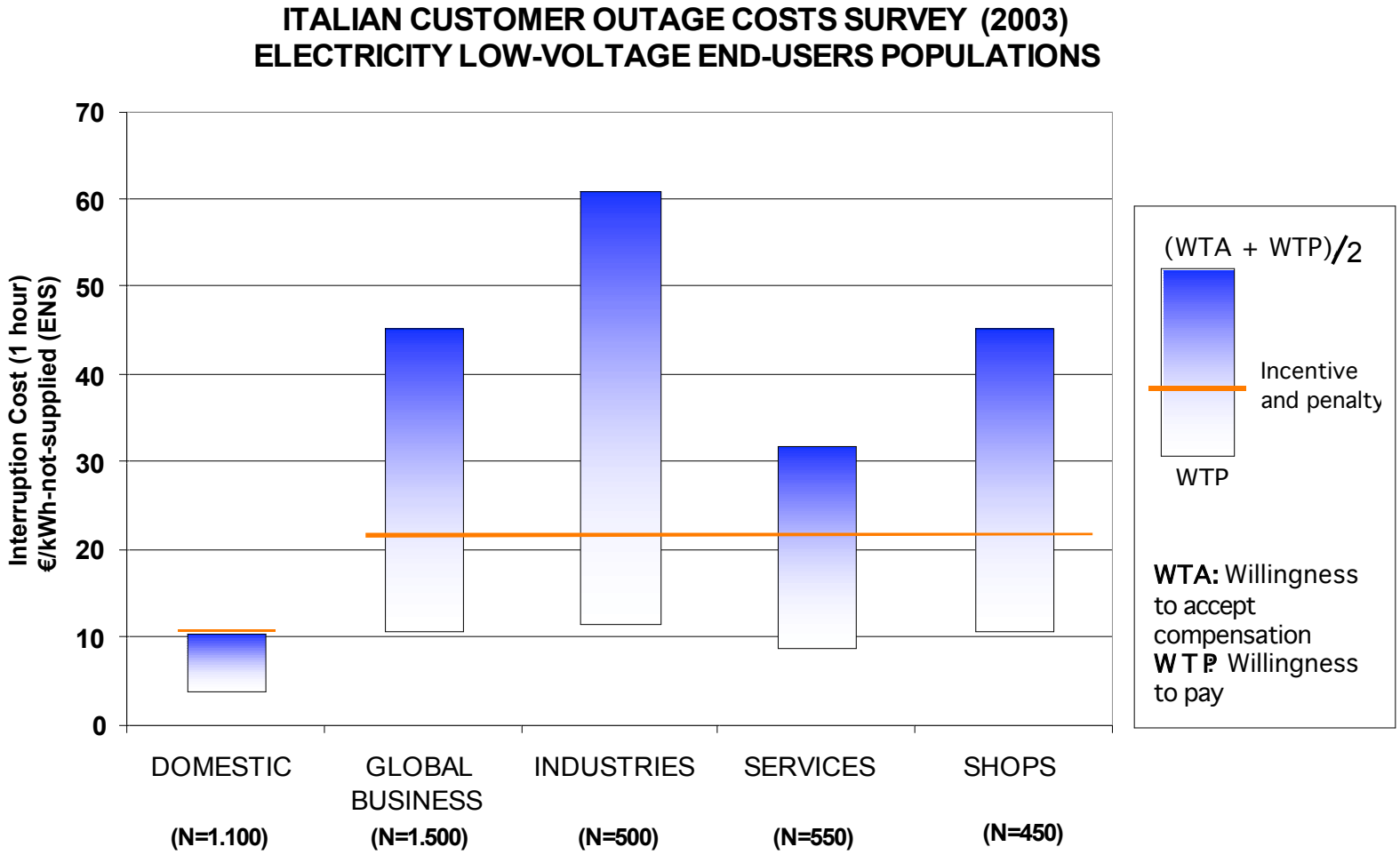
Direct costs



Normalized values: €/kWh (3 min., €/kW)

	Direct costs		WTA		WTP	
	Domestic	Business	Domestic	Business	Domestic	Business
3 minutes	8.02	55.16	5.35	34.16	1.38	4.90
1 hour	25.34	117.98	17.03	79.75	3.75	10.70
2 hours	20.41	83.79	13.92	57.09	2.68	7.75
4 hours	15.73	67.18	11.24	48.42	2.25	6.63
8 hours	9.68	40.01	6.89	28.99	1.36	3.98

WTP and (WTA+WTP)/2: incentive and penalty rate



Incentive rates set by regulators: Norway and Italy

Customer	Sector	Norway [€/kWh]	Italy [€/kWh]
Domestic	Residential	1.0	10.8
Business	Industrial	8.5	21.6
	Trade & Services	12.7	
Other	Agricultural	1.9	
	Public Services	1.7	
	Large Industry	1.7	n.a.

Consumer Expectations of DNOs and WTP for Improvements in Service

Report

June 2004 **145f/04**

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CONTENTS

Executive Summary

- Research was conducted to determine business and domestic electricity consumers' experience and satisfaction with the service received from the electricity distribution companies, their priorities for improvement in quality of service and standards, and their willingness to pay for improvements.

- Research comprised 2118 face-to-face domestic interviews and 1965 telephone business interviews both using a computer assisted stated preference method. Interviews covered all DNO areas, and were weighted to reflect DNO profiles of age, socio-economic group (SEG), rural and urban location and experience of cuts (domestic) and company size and experience of cuts (business). Total samples were weighted to represent the relative size of each DNO based on consumer numbers.

- The majority of urban domestic consumers say they have not experienced an unplanned power cut during the last year, while the majority of rural domestic consumers say they have done so. Typically consumers claim to experience only one or two cuts per year. Smaller businesses are more likely to say they experience more frequent and longer outages than large ones. Planned power cuts are perceived to be rare.

- Awareness of the current standards and targets is very low, yet both domestic and business consumers have high expectations in terms of quality of service. They expect rapid restoration of power, even after a major storm, and look for compensation after limited numbers of cuts per year or after a relatively short outage duration. Business consumers have particularly high expectations.

- A high proportion of domestic consumers do not contact their distributor during a power cut but those who do tend to find it easy to get through and to get the information they want. Business consumers are much more likely to contact their distributor, but their experience is also largely satisfactory.

- The survey used a form of conjoint analysis, stated preference, to identify the priorities that both sets of consumers would have for changes to the service. This approach was also used to identify consumer Willingness To Pay (WTP) for improvements in service explored during the survey, and Willingness to Accept (WTA) degradation in some service aspects. The context for this was that the existing service levels would be provided at current costs (there would be no need for extra investment cost to maintain existing service levels) and that their WTP was being identified within a context where all other prices (e.g. the fuel supply costs themselves or the cost of other utilities) were presumed to be held constant at current prices.

- A high priority for both business and domestic consumers is improving maximum restoration times following major storms. Domestic consumers are willing to pay £22 a year for improvement in maximum restoration times from the current level of 48 hours to 24 hours, business consumers are willing to pay 4.9%; an improvement to 36 hours is also valued, but less highly, and an increase in maximum restoration times to 60 hours would be negatively valued.

- Significant improvements in network resilience are valued by some consumers but not others; however, a major step change in network resilience such as major cuts being reduced to once every five years rather than once a year would be highly valued though less so than improving restoration times.

- Another high priority for domestic consumers is to ensure that they receive accurate information during a power cut. Willingness to pay to ensure that information is updated every two hours to ensure accuracy is £22, or 6% of their total bill, for this improvement. It is likely, however, that this value will have been 'enhanced' as a result of the implicit assumption in the evaluation that if it is not updated in this way the information they are given will not necessarily be accurate. There is no identified willingness to pay for a callback service (except for LPN). Domestic consumers show some altruism in being prepared to pay an additional 3% for a helpline for consumers medically dependent on electrical equipment.

- Consumers are prepared to pay for reductions in frequency of cuts, but only in their own areas. Both rural and urban consumers are prepared to pay about £20 to avoid a cut in the area relevant to them, but nothing towards reducing cuts elsewhere. Businesses place higher value on reducing urban cuts than rural cuts; only smaller companies value a reduction in rural cuts

- Most business consumers do not require improvements in information; only small companies show interest in a callback service, and there is no value given to a dedicated business helpline.

- Domestic and business consumers also value a reduction in the duration of power cuts. For domestic consumers, a reduction in the average length of cuts of 20 minutes would be valued at an equivalent level to the other two main priorities, improving restoration times to 24 hours or improving the accuracy of information. For business consumers the priority is not as high; such an improvement (ie 20 minutes) is valued at 2.8%, slightly less than reducing the number of urban cuts by one.

- Domestic consumers are not prepared to pay more for improvements to the multiple interruption standard. Companies are currently required to pay consumers £50 compensation if they experience four or more cuts longer than three hours. However, consumers expect a reduction in their total bills if the trigger for compensation is relaxed to five cuts longer than three hours; a discount of £21, or 5.7% of the bill, would be required in this case. Domestic consumers also see no value in implementing automatic compensation payments for only the 18 hour standard, but automatic compensation for all standards does have some value attached (£5, 1.5% of total bill).

- Businesses, in contrast, see some value in tightening the standard to three cuts or more (1.2%), but do not expect a reduction in their bill if the standard is relaxed to 5 cuts. Of a number of different levels of compensation improvements tested, only the highest level, comprising automatic compensation on a 14 hour standard with amounts linked to bill size, is valued at all, and even then only marginally by small companies (less than 1% of their total bill). In general, business consumers comment that compensation amounts are not adequate to make up for the business losses caused by power cuts.

- Both rural and urban residents are prepared to pay towards undergrounding of the network in national parks and areas of outstanding natural beauty. For each percent of the network undergrounded per year, consumers are prepared to pay about £2.50 per year, or 0.7% of the total bill.

1. INTRODUCTION

1.1 Background

OFGEM was formed in 1999 with the principal objective of protecting the interests of gas and electricity consumers in England, Wales and Scotland. Its objectives are to ensure both domestic and business consumers are afforded protection not only in terms of the price they pay but also the quality of service they receive from Distribution Network Operators (DNOs). The existing regulatory framework provides such protection in terms of quality of service through two main mechanisms:

- Guaranteed and Overall Standards of Performance (GOSPs) and;
- A quality of service incentive scheme under the Information and Incentives Project (IIP).

As part of the distribution price control review OFGEM is reviewing the existing quality of service arrangements to ensure that DNOs continue to be provided with appropriate incentives to deliver a good quality of service to consumers.

In order to support this work, OFGEM commissioned a research study to provide a detailed understanding of which aspects of service are valued by consumers, the relative priorities placed on different outputs and consumers' willingness to pay for improvements in service.

The study comprised a qualitative phase and two quantitative phases. This report details the findings from the second quantitative phase conducted in March and April 2004.

1.2 Objectives

Overall Objectives

The outputs from this study as a whole are designed to inform the following:

- The areas which will be financially incentivised (or in which additional reporting requirements will be introduced);
- Target setting;
- Incentive rates; and
- Compensation payments under the GOSPs.

Specific Objectives

The research is specifically required to provide an understanding of:

- Consumer experience and satisfaction with the quality of service they receive;

- Areas of quality of service, environmental and social outputs that consumers value and their relative priorities among these;

- Consumer awareness of the GOSPs, their views on improvements or extensions to the GOSPs, their relative priorities and their willingness to pay for such changes;

- Consumer expectations of average levels of quality of service, their relative priorities among potential improvements in different aspects of quality and their willingness to pay for improvements;

- Consumer expectations regarding the resilience of their power supply to bad weather or other exceptional events and willingness to pay for improvements in this area;

- Consumer views on variations in quality of service delivered in different geographical area and all consumers' willingness to pay for improvements in service to worst-served consumers or consumers in rural areas; and

- Consumer views on the benefits of undergrounding parts of DNOs networks and their willingness to pay for a programme of selective undergrounding.

2. METHODOLOGY

2.1 Introduction

The research comprised stated preference interviews with both domestic and business consumers across England, Wales and Scotland. Stated preference is a research technique also known as 'trade-off' or conjoint research. It is a method of obtaining relative importance and willingness to pay for changes in service.

The basis of the technique is the concept of utility. Utility theory postulates that each good, service, or activity conveys a benefit to the consumer; he or she (in purchase behaviour or choice of activities) seeks to maximise that benefit and will make choices that do so.

The utility of a product or service is seen to be the sum of utilities of the features of that product/service. Each of these factors, or attributes, conveys a benefit to the purchaser (or disbenefit, in the case of price).

When making their choices people 'trade off' the bundle of utilities of one alternative with the other. They then choose the one that conveys the highest net utility.

Stated preference techniques seek to measure the utility associated with a product or service and to derive the part-utilities associated with each attribute of the service.

The measurement of utilities through stated preference techniques is undertaken in an experiment or exercise that forms the major part of the interview. They are offered a series of choices between two packages, each of which describes the service in terms of the attributes for which measurement is required.

Respondents are asked to make a choice between one of the two packages in each pair. The way in which the packages are designed conform to a statistical design and may therefore be analysed. Logit analysis is used.

The output of the analysis is a utility function (or model) comprised of utility weights for the attributes being examined. The weights show the relative preferences for each attribute and the strength of those preferences. Where cost is included, as in this case, its utility weight can be used to derive a willingness to pay for other attributes.

2.2 Domestic

The fieldwork was undertaken between 9 February 2004 and 29 March 2004. The interviews were conducted in the respondents' homes, using a laptop computer. Interviews lasted 20-25 minutes on average and respondents received a £5 Boots voucher as incentive for taking part.

Sample

- The target for the total sample was 2100 interviews, 150 within each of the 14 DNO areas. Within each DNO area minimum targets were set by age, in three

categories (16-29 years, 30-49 years, and 50 and above), socio-economic groups (SEG) and previous experience of cuts.

Socio-economic groups (SEG) are a standard method of classifying households. They are defined by asking a standard classification question as follows:

"What is the occupation of the head of your household?"

Respondents are then classified accordingly using a comprehensive glossary. Broad definitions are as follows:

- ABs:
  - These represent approximately 17% of the total population
  - Group A includes: professional people; very senior managers in business or commerce; top civil servants; retired people who were previously one of the foregoing and their widow/widowers. Group B includes: middle management executives in large organisations; principal officers in local government or the civil service; top management or owners of small business concerns, educational and service establishments; and retired people who were previously in group B and their widow/widowers
- C1C2s:
  - These represent approximately 51% of the total population
  - C1 includes: junior management; owners of small establishments; all others in non-manual positions; retired people who were previously in the C1 group and their widow/widowers. C2 includes: all skilled manual workers; manual workers with responsibility for other people; retired people who were previously in the C2 group if receiving pensions from their job; widows/widowers of those in C2 if receiving pensions from their late spouse's job
- DEs:
  - These represent approximately 32% of the population
  - D includes: all semi-skilled and unskilled manual workers; apprentices and trainees to skilled workers; retired people previously in group D with pensions from their job; widows/widowers of those in D if receiving pension from their spouse's job. E includes: those entirely dependent on the state long-term through sickness, unemployment, old age or other reasons; those unemployed for a period exceeding six months; casual workers and those without a regular income.

A quota was also set on type of location (urban/rural), except for the EDF Energy Networks (LPN) area, which does not include any rural locations, to ensure adequate representation of all groups in the sample.

As interviews were to be conducted in the home, a cluster sampling method was used. Within each of the 14 DNO areas, between 12 and 20 sampling points were selected. The sampling points were selected by allocating the postcodes in the DNOs' area to either the rural or the urban category, and then selecting postcodes at random from each list to make up the number of sampling points required. Interviewers then recruited respondents house to house within the postcode, approaching every third address, and recruiting on the doorstep using a short questionnaire to identify the decision-maker and to determine whether they fell within the required quotas for the study. Those agreeing to take part were then interviewed at that time or at a further appointment.

In total, 2118 interviews were conducted with domestic consumers.

For each DNO area except EDF Energy Networks (LPN) the targets set were as follows:

Table 1:Domestic Quotas

	Urban Number of interviews	**Rural Number of interviews**
Experience of Cuts	Minimum 37	Minimum 37
No Experience	No quota	No quota
16-29 years	Minimum 9	Minimum 23
30-49	Minimum 14	
50+	Minimum 16	Minimum 16
AB	Minimum 10	Minimum 10
C1C2	Minimum 20	Minimum 20
DE	Minimum 11	Minimum 11
Total	75	75

For EDF Energy Networks (LPN) the targets were:

Table 2: EDF Energy Networks (LPN) Domestic Quota

	Urban
Experience of Cuts	Minimum 75
No Experience	No quota
16-29 years	Minimum 18
30-49	Minimum 28
50+	Minimum 32
AB	Minimum 20
C1C2	Minimum 40
DE	Minimum 22
Total	150

Interviews achieved were as follows:

Table 3: Domestic Interview Numbers Achieved

	Location		Exp Cuts		Age			SEG			Total
DNO	Rural	Urban	Cuts	No Cuts	16-29	30-49	50+	AB	C1C2	DE	
Central Networks (West)	77	74	98	53	37	56	58	33	68	50	151
EDF Energy Networks (EPN)	75	76	82	69	17	64	70	37	72	42	151
Central Networks (East)	76	74	89	61	17	75	58	38	73	39	150
SP Manweb	63	89	53	99	28	67	57	31	60	61	152
NEDL	75	75	71	79	26	67	57	21	52	77	150
Scottish Hydro Electric	76	72	67	81	19	69	60	27	81	39	148
Scottish Power	82	70	83	69	28	63	61	41	64	47	152
Southern Electric	77	73	108	42	22	79	49	36	69	44	150
EDF Energy Networks (SPN)	75	75	80	70	13	50	86	30	71	49	150
United Utilities	76	74	86	64	18	80	52	30	78	42	150
WPD (South Wales)	78	86	76	88	30	68	64	32	70	61	162
WPD (South West)	74	75	95	54	19	71	59	33	69	46	149
YEDL	74	75	58	91	31	60	58	26	71	50	149
EDF Energy Networks (LPN)	0	154	59	95	52	74	28	19	72	62	154
Total	978	1142	1105	1015	344	924	817	434	970	709	2118

Domestic Weighting Process

The data were weighted by age, SEG, urban/rural location and experience of cuts in the past year to reflect the profile of each DNO, and then by consumer numbers for each DNO. The total weighted sample is therefore reflective of the relative number and profile of consumers for each DNO area.

The sources of the weighting information were:

- Urban versus rural households by each DNO, from figures provided by individual DNOs;
- Number of households experiencing interruptions by each DNO, from figures estimated by Ofgem;
- SEG segmentation taken from the BARB Establishment survey 1997 (where regions are defined by ITV areas);
- Age segmentation taken from the Census 2001; and
- Relative size of each DNO determined from consumer numbers provided by Ofgem.

The variables used in the weighting are not interlocking; that is to say, while we know, for example, what percentage of households in a DNO are in each age group, and we know what percentage of households in a DNO experience cuts, we do not have the information on what percentage of households in each age group experience cuts as compared to the other groups. This means that rim weighting is required, where the

sample is weighted by each variable in turn. After the first weight is applied, the data set accurately reflects the distribution of that variable. When the data set is weighted by the second variable, however, the first variable may no longer match the targets. As each subsequent weight is applied, the earlier variables may differ more from the targets. After passing through all the variables, we have a set of weights that will match the target on the last variable but not necessarily on the other variables.

After a series of iterations and changing the order of the variables, the following solution was reached minimising the difference between the target and actual values for each variable. The tables below show the weighted distributions and the targets. SEG was the first variable used.

Table 4: Weighted SEG Breakdown

ITV Area	DNO	ABs (%)	C1C2 (%)	DE (%)
London	EDF Energy Networks (LPN)	20	44	35
Midlands	Central Networks (East) & Central Networks (West)	16	48	36
North West	United Utilities	13	43	44
Yorkshire	YEDL	15	44	39
Central Scotland & Border	ScottishPower	13	45	42
Wales & West	SP Manweb & WPD (South Wales)	17	47	36
South & South East	Southern & EDF Energy Networks (SPN)	21	52	27
North East	NEDL	15	40	45
East	EDF Energy Networks (EPN)	16	52	33
South West	WPD (South West)	16	53	30
North Scotland	Scottish Hydro Electric	18	44	37

On this and subsequent tables please note that the figures may not sum to 100% due to rounding.

Table 5: Target SEG Breakdown: taken from BARB Establishment

ITV Area	DNO	AB(%)	C1C2 (%)	DE (%)
London	EDF Energy Networks (LPN)	23	47	30
Midlands	Central Networks (East) & Central Networks (West)	16	49	35
North West	United Utilities	17	45	38
Yorkshire	YEDL	14	48	39
Central Scotland & Border	ScottishPower	15	45	39
Wales & West	SP Manweb & WPD (South Wales)	18	47	36
South & South East	Southern & EDF Energy Networks (SPN)	23	50	27
North East	NEDL	15	43	43
East	EDF Energy Networks (EPN)	18	51	31
South West	WPD (South West)	18	54	29
North Scotland	Scottish Hydro Electric	18	46	36

Age was the second variable used.

Table 6: Weighted Age Breakdown

Census Area	DNO	16-29 (%)	30-49 (%)	50+ (%)
North West	United Utilities	23	35	43
North East	NEDL	24	39	37
Yorkshire and the Humber	YEDL	25	37	38
East Midland	Central Networks (East)	22	34	44
West Midlands	Central Networks (West)	22	36	42
East of England	EDF Energy Networks (EPN)	24	35	42
London	EDF Energy Networks (LPN)	30	42	27
South East	EDF Energy Networks (SPN) & Southern	23	37	39
South West	WPD (South West)	20	35	45
Wales	WPD (South Wales) & SP Manweb	23	37	40
Scotland	Scottish Power & Scottish Hydro Electric	24	35	40

Table 7: Target Age Breakdown as in Census 2001

Census Area	DNO	16-29 (%)	30-49 (%)	50+ (%)
North West	United Utilities	22	36	43
North East	NEDL	21	36	43
Yorkshire and the Humber	YEDL	22	36	42
East Midland	Central Networks (East)	21	36	43
West Midlands	Central Networks (West)	22	36	43
East of England	EDF Energy Networks (EPN)	21	36	43
London	EDF Energy Networks (LPN)	27	39	33
South East	EDF Energy Networks (SPN) & Southern	21	36	43
South West	WPD (South West)	20	34	46
Wales	WPD (South Wales) & SP Manweb	21	34	45
Scotland	Scottish Power & Scottish Hydro Electric	22	37	42

The third variable to be used in the rim weighting was the rural versus urban split.

Table 8: Weighted Rural/Urban Breakdown

DNO	Rural (%)	Urban (%)
Central Networks (West)	45	55
EDF Energy Networks (EPN)	29	71
Central Networks (East)	45	55
SP Manweb	32	68
NEDL	32	68
Scottish Hydro Electric	65	35
Scottish Power	52	48
Southern Electric	39	61
EDF Energy Networks (SPN)	32	68
United Utilities	30	70
WPD (South Wales)	31	69
WPD (South West)	57	43
YEDL	32	68
EDF Energy Networks (LPN)	0	100

Table 9: Target Rural/Urban Breakdown

DNO	Rural (%)	Urban (%)
Central Networks (West)	52	48
EDF Energy Networks (EPN)	29	71
Central Networks (East)	48	52
SP Manweb	31	69
NEDL	28	72
Scottish Hydro Electric	65	35
Scottish Power	48	52
Southern Electric	44	56
EDF Energy Networks (SPN)	24	76
United Utilities	32	68
WPD (South Wales)	29	71
WPD (South West)	62	38
YEDL	31	69
EDF Energy Networks (LPN)	0	100

Q1 (question asking about unplanned power cuts) was the last but one variable used in the stepwise process.

Table 10: Weighted Data on % of consumers not interrupted

DNO	% not interrupted
Central Networks (West)	47
EDF Energy Networks (EPN)	46.5
Central Networks (East)	52
SP Manweb	73
NEDL	55
Scottish Hydro Electric	49
Scottish Power	62
Southern Electric	46
EDF Energy Networks (SPN)	47
United Utilities	56
WPD (South Wales)	51
WPD (South West)	49
YEDL	60
EDF Energy Networks (LPN)	75

Table 11: Target Data on % of consumers not interrupted

DNO	% not interrupted
Central Networks (West)	47
EDF Energy Networks (EPN)	46.5
Central Networks (East)	52
SP Manweb	73
NEDL	55
Scottish Hydro Electric	49
Scottish Power	62
Southern Electric	46
EDF Energy Networks (SPN)	47
United Utilities	56
WPD (South Wales)	51
WPD (South West)	49
YEDL	60
EDF Energy Networks (LPN)	75

The last step in the process was to weight each DNO to reflect relative consumer numbers.

Table 12: Weighted Domestic Sample Size by DNO

DNO	Consumer Number	Weighted Sample Size
Central Networks (West)	2,323,792	175
EDF Energy Networks (EPN)	3,415,372	257
Central Networks (East)	2,471,437	186
SP Manweb	1,468,457	110
NEDL	1,518,745	114
Scottish Hydro Electric	684,124	51
Scottish Power	1,962,975	147
Southern Electric	2,760,987	207
EDF Energy Networks (SPN)	2,168,231	163
United Utilities	2,279,297	171
WPD (South Wales)	1,076,287	81
WPD (South West)	1,466,838	110
YEDL	2,171,755	163
EDF Energy Networks (LPN)	2,255,232	169

Domestic Questionnaire and Stated Preference Exercises

The recruitment questionnaires, main questionnaires and stated preference show materials can be found in the Appendices.

The questionnaire included some background questions on electricity consumption and experience of cuts, and attitudinal questions about consumers' expectations in terms of quality of service and service standards. Awareness of the service standards was also measured. The main part of the interview was a series of stated preference exercises designed to obtain consumers' priorities between, and willingness to pay for, the following potential changes in service:

- an increase or decrease in the number of power cuts in rural areas over 5 years: up to 3 more or fewer cuts than the DNO's current average;
- an increase or decrease in the number of power cuts in urban areas over 5 years: up to 3 more or fewer cuts than the DNO's current average;
- longer or shorter average power cut durations: up to 20 minutes longer or shorter than the DNO's current average;
- improvement in the resilience of the network: chance of 1% of consumers having a 24hr + outage following a major storm currently once per year, improvement to once every 2 years or once every 5 years;
- maximum time to restore consumers after a major storm decreasing to 24 hours or 36 hours compared to current (48 hrs) or increasing to 60 hours;
- consumers entitled to compensation after 3 (fewer) or 5 (more) unplanned cuts of over 3 hours. The standard is currently set at four unplanned cuts;

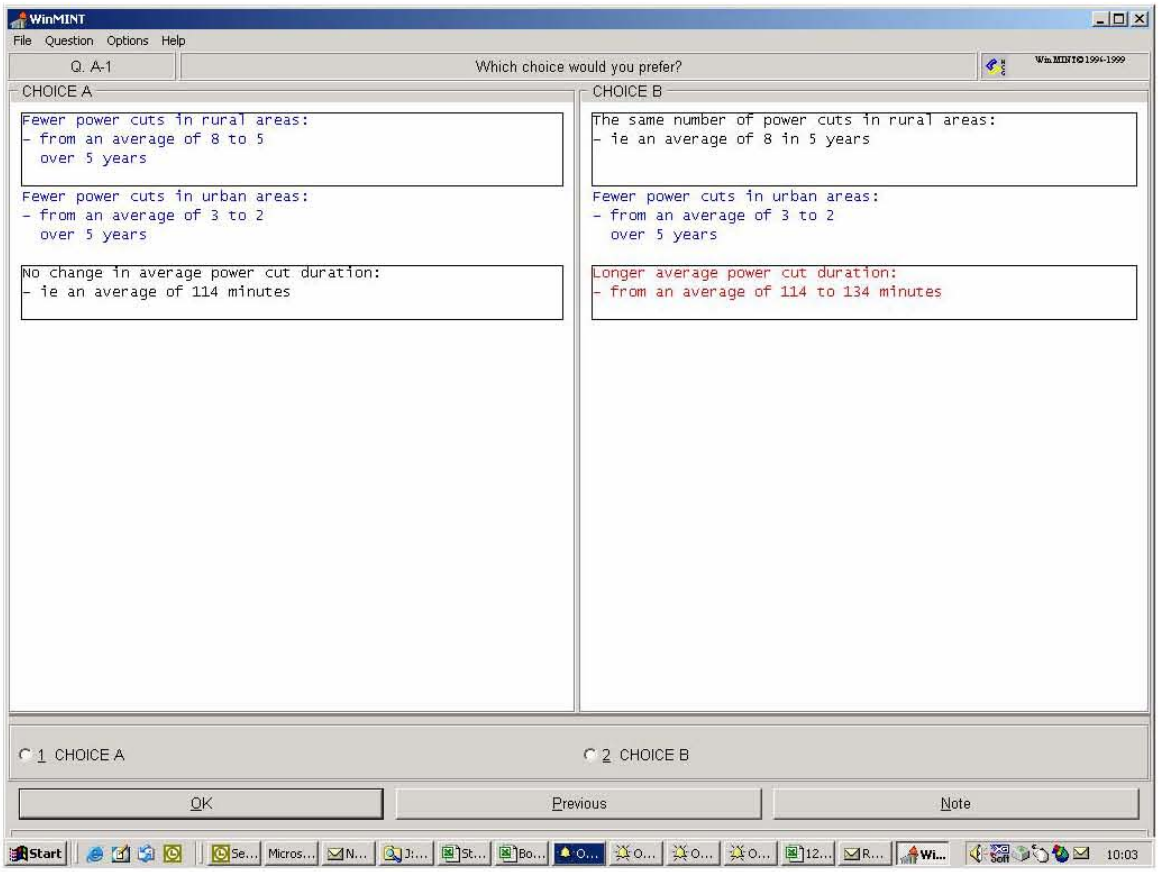
- compensation provided automatically rather than having to be claimed: for the 18hr interruption standard only, or for all standards;

- changes to the provision of information during a power cut: more frequent updating, call backs if required, and a special helpline for medically dependent consumers; and

- a commitment to undergrounding up to 7.5% of the network per year on an ongoing basis in national parks and areas of outstanding natural beauty to reduce visual impact.

These variables were arranged in a series of four stated preference exercises. Each exercise involves a series of six to eight pairwise choices, in each of which the respondent chooses his or her preferred package of improvements from a choice of two. Three variables were included in each of the first three exercises, and the final exercise traded bundles of improvements with changes in the size of the bill. This provides the monetary values and overall priorities between all the changes tested.

An example of pairwise choice is shown below.



In the EDF Energy Networks (LPN) area, which does not include any rural locations, a separate design was used which excluded variables not relevant to the EDF Energy Networks (LPN) area. The variables tested in the EDF Energy Networks (LPN) area were:

- an increase or decrease in the number of power cuts in urban areas over 5 years: up to 3 more or fewer cuts than the EDF Energy Networks (LPN) current average;

- longer or shorter average power cut durations: up to 20 minutes longer or shorter than the EDF Energy Networks (LPN) current average;

- consumers entitled to compensation after fewer or more unplanned cuts than now;

- compensation provided automatically rather than having to be claimed: for the 18hr interruption standard only, or for all standards;

- changes to the provision of information during a power cut: more frequent updating, call backs if required, and a special helpline for medically dependent consumers; and

- a commitment to undergrounding of the network to reduce visual impact.

As fewer variables were tested, the EDF Energy Networks (LPN) consumers took part in only three exercises.

2.3 Business

The fieldwork was carried out between 26 February 2004 and 6 May 2004. Interviews were conducted by telephone from Accent's dedicated telephone units based in Bristol and Edinburgh using a computer-assisted interview. Interviews lasted 24 minutes on average. There was no incentive for taking part.

Sample

The target for the total sample was 2100 interviews, 150 within each of the 14 DNO areas. Within each DNO area minimum targets were set by size, measured by maximum demand or bill size, in three categories: large (over 1MW or £159,000 annual bill); medium (over 100kW or £15,000 per year); and small. This was to ensure adequate representation of all groups in the sample. A quota was also set on experience of power cuts.

The sample source was purchased from Sample Sources' the UK Biz database, based on the Experian National Business Database, the standard list of just under 2m UK businesses. The list was divided into strata according to size by number of employees. These strata were intended broadly to approximate to the size bands listed above, to assist in targeting. The list was also divided into regions. Companies were then selected at random from these lists for interview.

Respondents were recruited by telephone using a short recruitment questionnaire to identify the decision-maker for the organization, establish whether they were in-scope for the study and obtain agreement for the further interview. Respondents were then sent, by post, fax or email, the show material relating to the stated preference exercise choices, and contacted at a prearranged time for the further interview to take place. The

initial refusal rate was 22%. The conversion rate between recruitment and interview was 62%. This is typical for this type of survey.

In total, 1965 interviews were conducted with business consumers.

For each DNO area the targets set were as follows:

Table 13: Business Quotas

	Number of interviews
Experience of cuts	Minimum 75
Not experienced	No Quota
Large	25-50
Medium	40-70
Small	40-70
Total	150

Interviews achieved were as follows:

Table 14: Business Interviews Achieved

DNO	Cuts	No Cuts	Large	Medium	Small	Total
Central Networks (West)	77	62	20	51	68	139
EDF Energy Networks (EPN)	69	61	19	36	75	130
Central Networks (East)	68	73	10	38	93	141
SP Manweb	61	71	13	42	77	132
NEDL	68	70	21	39	78	138
Scottish Hydro Electric	63	75	7	30	101	138
Scottish Power	70	84	23	63	68	154
Southern Electric	78	67	21	64	60	145
EDF Energy Networks (SPN)	85	78	7	55	101	163
United Utilities	53	84	16	61	60	137
WPD (South Wales)	63	71	10	31	93	134
WPD (South West)	72	67	17	37	85	139
YEDL	63	73	18	46	72	136
EDF Energy Networks (LPN)	62	77	14	44	81	139

Business Weighting

The business data were weighted to match the experience of cuts within each DNO area, according to figures provided by each DNO area. The overall sample was then weighted by consumer numbers for each DNO so that the total weighted sample reflects the relative number of consumers. As these were the only variables used the weighted data reflects the targets perfectly.

Table 15: Weighted Data on % of consumers not interrupted

DNO	% not interrupted
Central Networks (West)	47
EDF Energy Networks (EPN)	46.5
Central Networks (East)	52
SP Manweb	73
NEDL	55
Scottish Hydro Electric	49
Scottish Power	62
Southern Electric	46
EDF Energy Networks (SPN)	47
United Utilities	56
WPD (South Wales)	51
WPD (South West)	49
YEDL	60
EDF Energy Networks (LPN)	75

Table 16: Weighted Business Sample Size by DNO

DNO	Consumer Number	Weighted Sample Size
Central Networks (West)	2,323,792	163
EDF Energy Networks (EPN)	3,415,372	239
Central Networks (East)	2,471,437	173
SP Manweb	1,468,457	103
NEDL	1,518,745	106
Scottish Hydro Electric	684,124	48
Scottish Power	1,962,975	138
Southern Electric	2,760,987	194
EDF Energy Networks (SPN)	2,168,231	152
United Utilities	2,279,297	160
WPD (South Wales)	1,076,287	75
WPD (South West)	1,466,838	103
YEDL	2,171,755	152
EDF Energy Networks (LPN)	2,255,232	158

Business Questionnaire and Stated Preference Exercises

The recruitment questionnaires, main questionnaires and stated preference show materials can be found in the Appendices.

The business questionnaire followed a very similar pattern to the domestic questionnaire. The stated preference exercises examined the following potential changes in service:

- an increase or decrease in the number of power cuts in rural areas over 5 years: up to 3 more or fewer cuts than the DNO's current average (not tested in the EDF Energy Networks (LPN) area);
- an increase or decrease in the number of power cuts in urban areas over 5 years: up to 3 more or fewer cuts than the DNO's current average;
- longer or shorter average power cut durations: up to 20 minutes longer or shorter than the DNO's current average;

- improvement in the resilience of the network: chance of 1% of consumers having a 24hr + outage following a major storm currently once per year, improvement to once every 2 years or once every 5 years (not EDF Energy Networks (LPN));

- maximum time to restore consumers after a major storm decreasing to 24 hours or 36 hours compared to current (48 hrs) or increasing to 60 hours (not EDF Energy Networks (LPN));

- consumers entitled to compensation after 3 (fewer) or 5 (more) unplanned cuts of over 3 hours. The standard currently requires compensation to be paid out after 4 cuts longer than 3 hours;

- changes to the compensation arrangements: compensation after 14hrs rather than 18; a higher level of compensation for larger businesses, based on a percentage of bill size; and a higher level with the addition that it would be automatically paid, rather than having to claim; and

- changes to the provision of information during a power cut: call backs if required, and a dedicated helpline for business consumers.

3. DOMESTIC CONSUMERS' EXPERIENCE AND ATTITUDES

Please note that numbers in tables and figures may not add to 100% due to rounding.

3.1 Bill Size

As part of the interview, consumers were asked to check their latest bill and estimate their annual bill size. The average bill size reported was £376. This is somewhat higher than the actual average domestic bill. The most likely reason for the high estimates is the timing of the fieldwork, immediately following the coldest quarter of the year. Although respondents were asked to take this into account, their estimates are likely to have been affected by this.

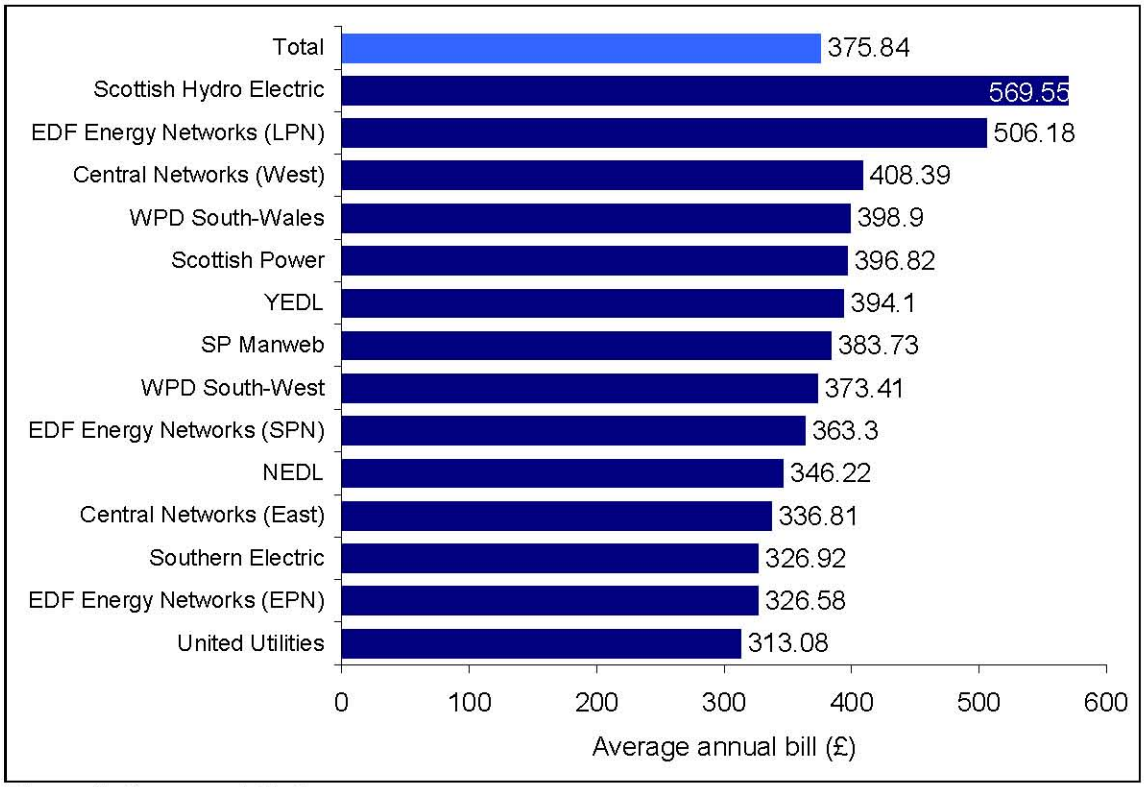


Figure 1: Average bill size

3.2 Experience of Cuts

The majority (60%) of domestic consumers in rural areas say they have experienced at least one power cut of more than 3 minutes in the last year, while a minority (38%) of urban consumers say they have experienced such a cut.

Frequent cuts are rare; most consumers say they have experienced only one or two in the past year. Rural consumers are more likely to report more frequent and longer power cuts than urban consumers.

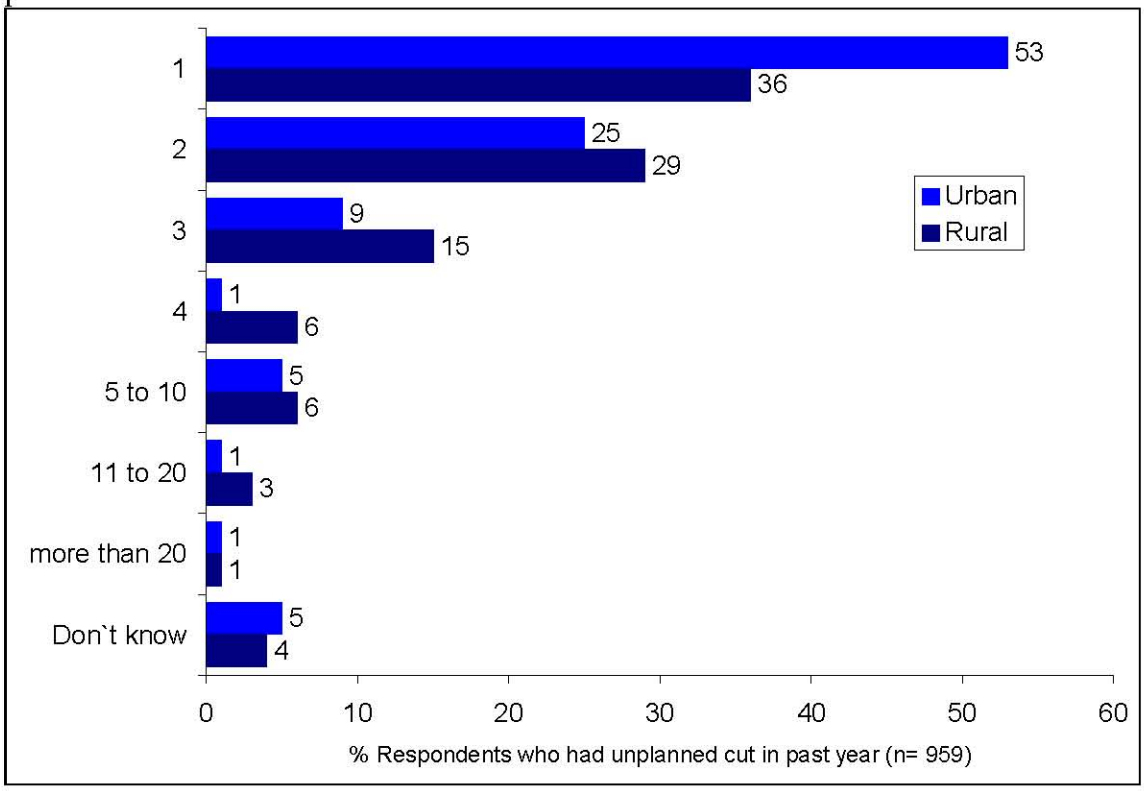


Figure 2: Frequency of unplanned cuts in past year

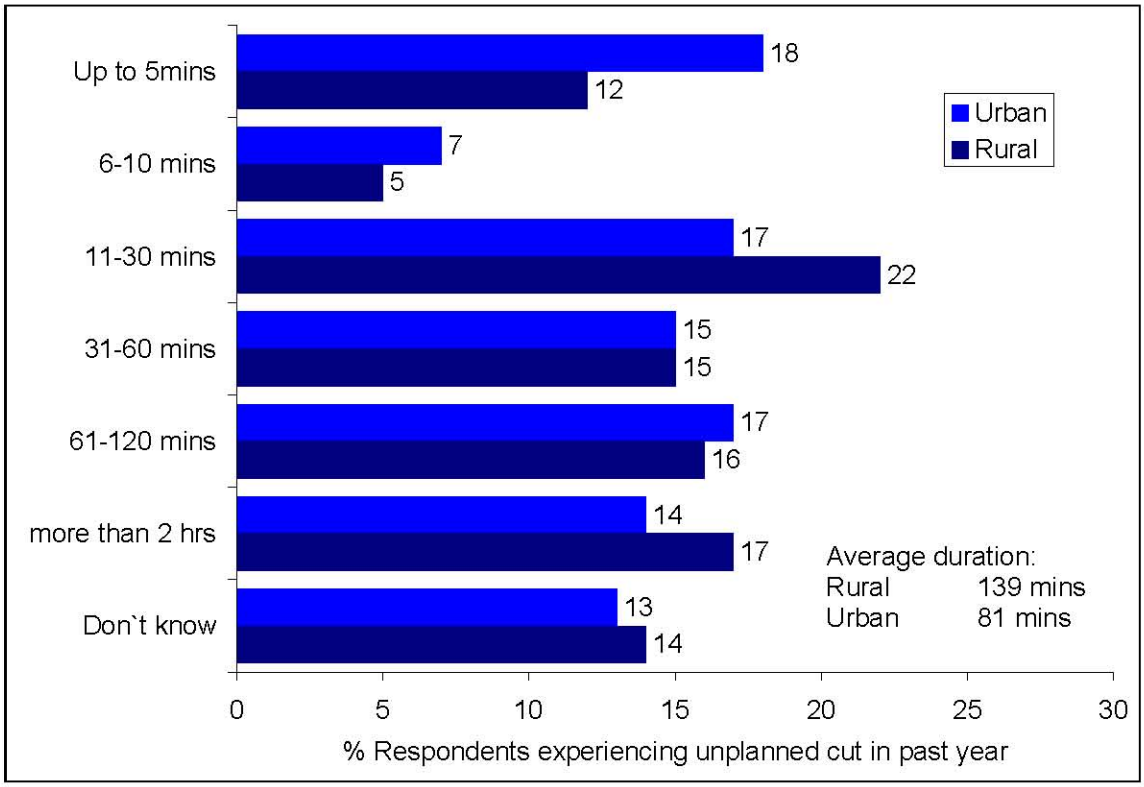


Figure 3: Length of most recent unplanned power cut

A very small proportion of consumers (8%) said they had experienced planned cuts in the past year. This typically occurred only once in the year, but these cuts were perceived to be longer on average than the unplanned cuts.

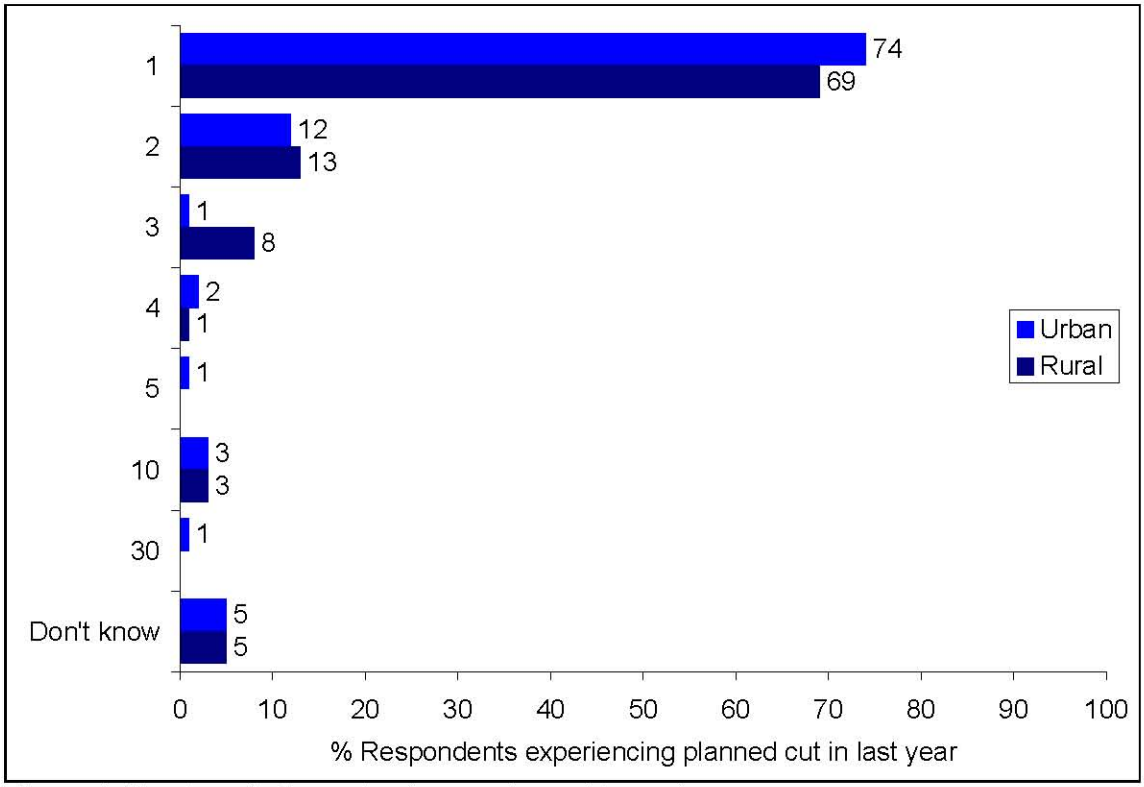


Figure 4: Number of planned cuts experienced in past year

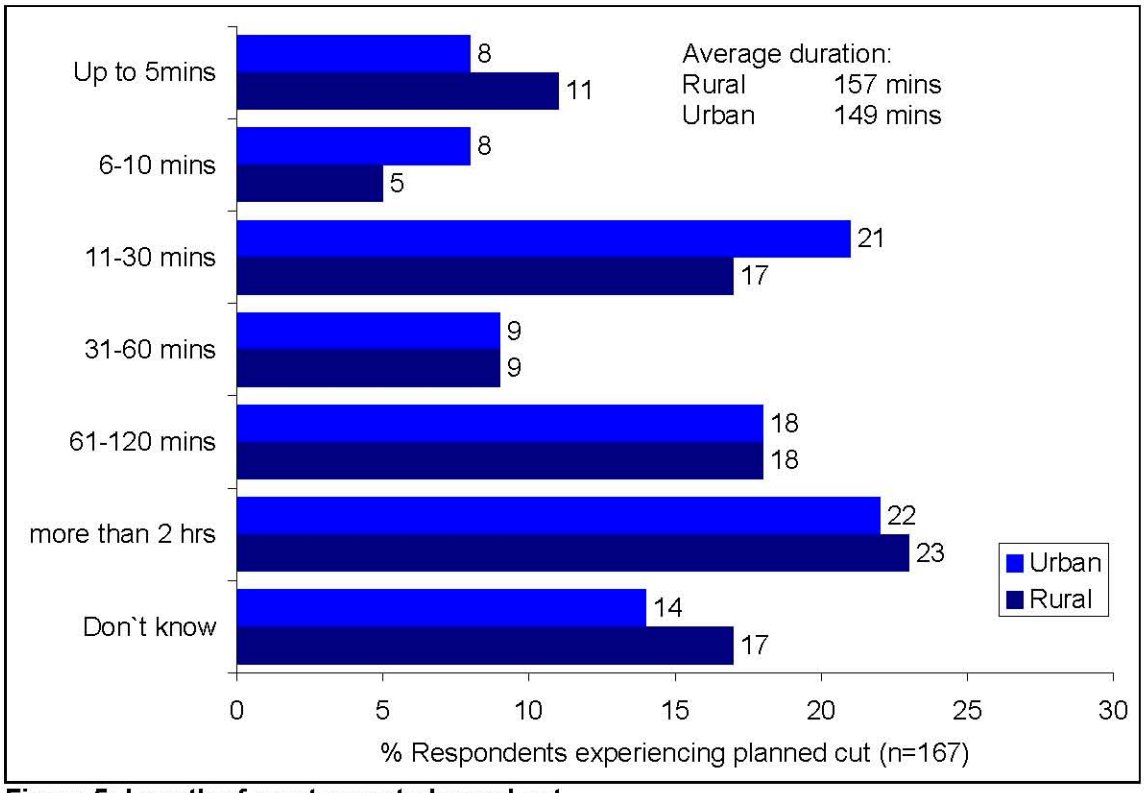


Figure 5: Length of most recent planned cut

3.3 Experience of Contacting Distributor During Power Cut

Most domestic consumers did not attempt to contact the distributor when they experienced an unplanned power cut. Of the 23% who did attempt to contact the distributor, four out of five (80%) were able to get through, and the time to get through was generally perceived as being short (55% got through in one minute or less).

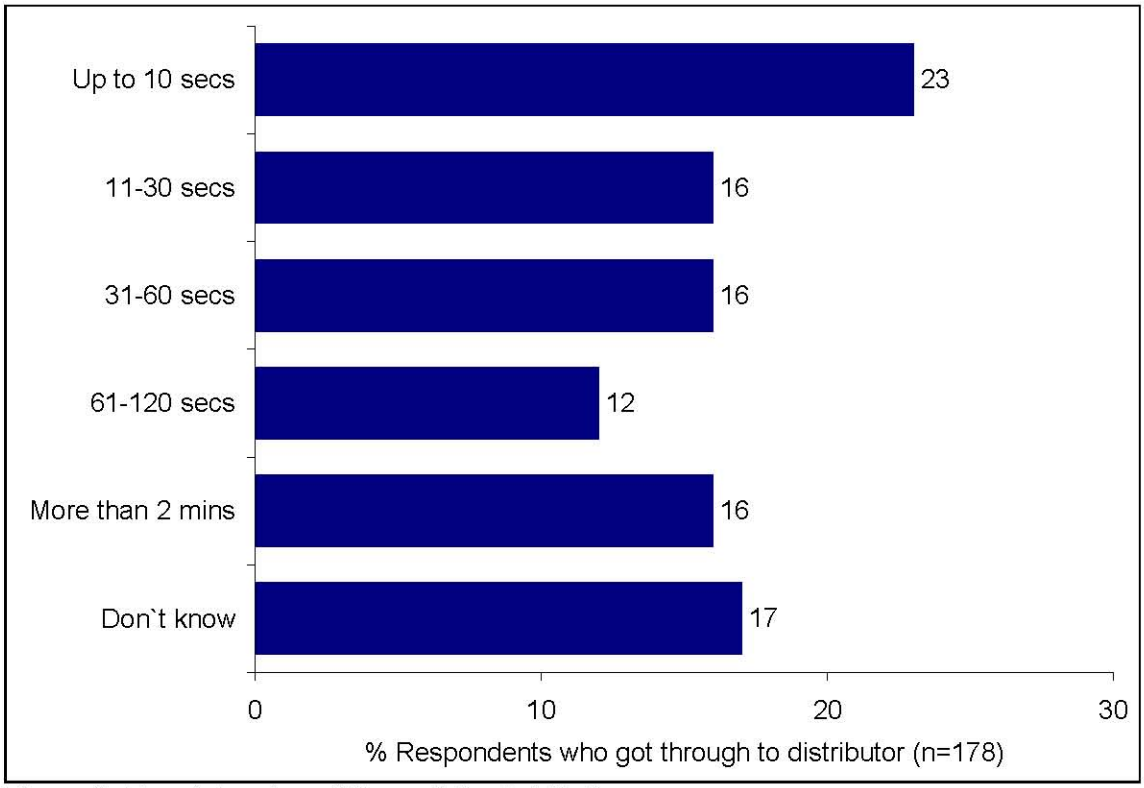


Figure 6: Time taken to get through to distributor

Those who did get through were evenly divided between those who received an automated response and those who spoke to someone. The small number of consumers who achieved contact with their distributor had a positive experience. The majority (79%) got the information they wanted and nine out of ten (89%) said the information they received was correct. Those who spoke to someone, rather than getting an automated message, were more likely to get the information they wanted and to say that it was correct.

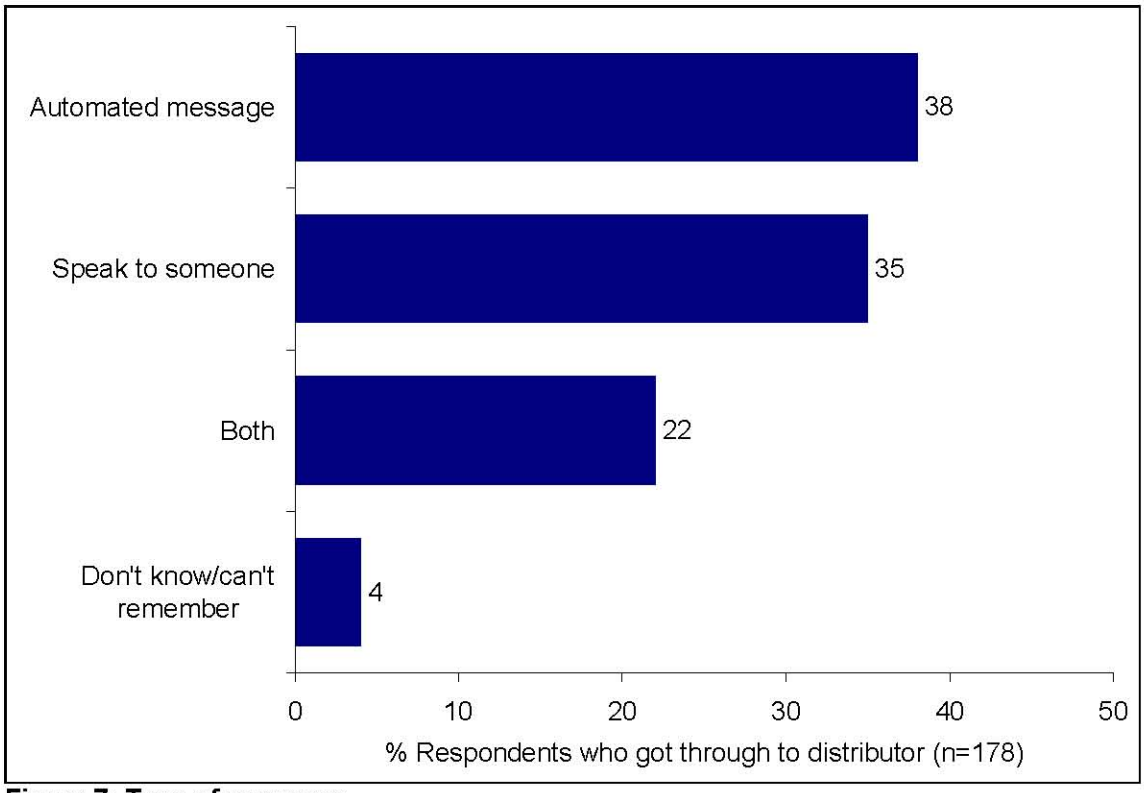


Figure 7: Type of response

Table 17: Quality of information by type of response

	Type of response			Total %
	Automated message %	Spoke to someone %	Both %	
Got the information they were looking for	72	86	87	79
Information was correct	80	99	77	89

3.4 Awareness of Standards and Targets

Awareness of the standards and targets currently in place is very low among domestic consumers. Less than 10% of consumers are aware of any of the standards or targets.

Table 18: Awareness of standards

Standard	% aware
Distributors should restore consumers' supplies within 18hrs following unplanned interruptions. Failure results in a penalty payment of £50 for domestic customers for the first 18 hours plus £25 for each additional 12 hours.	6
Consumers entitled to penalty payment of £50 if they have 4 or more power cuts each longer than 3 hrs in a single year.	3
Consumers must be given at least 2 days notice of planned power cut. Failure to do so results in a penalty payment of £20 for domestic customers.	7

3.5 Expectations of Quality of Service

Domestic consumers have high expectations regarding quality of service. Although most (82%) consumers believe it is reasonable for a power cut to occur in major storm, two thirds (69%) believe that distributors should be doing more to reduce the impact of severe weather on their networks. Consumers expect power to be restored quickly. Even after a major storm affecting 1% of the distributor's consumers, only 12% expect restoration to take 24 hours or more. Nearly half (46%) of consumers expect power to be restored in these circumstances within 3 hours, or less.

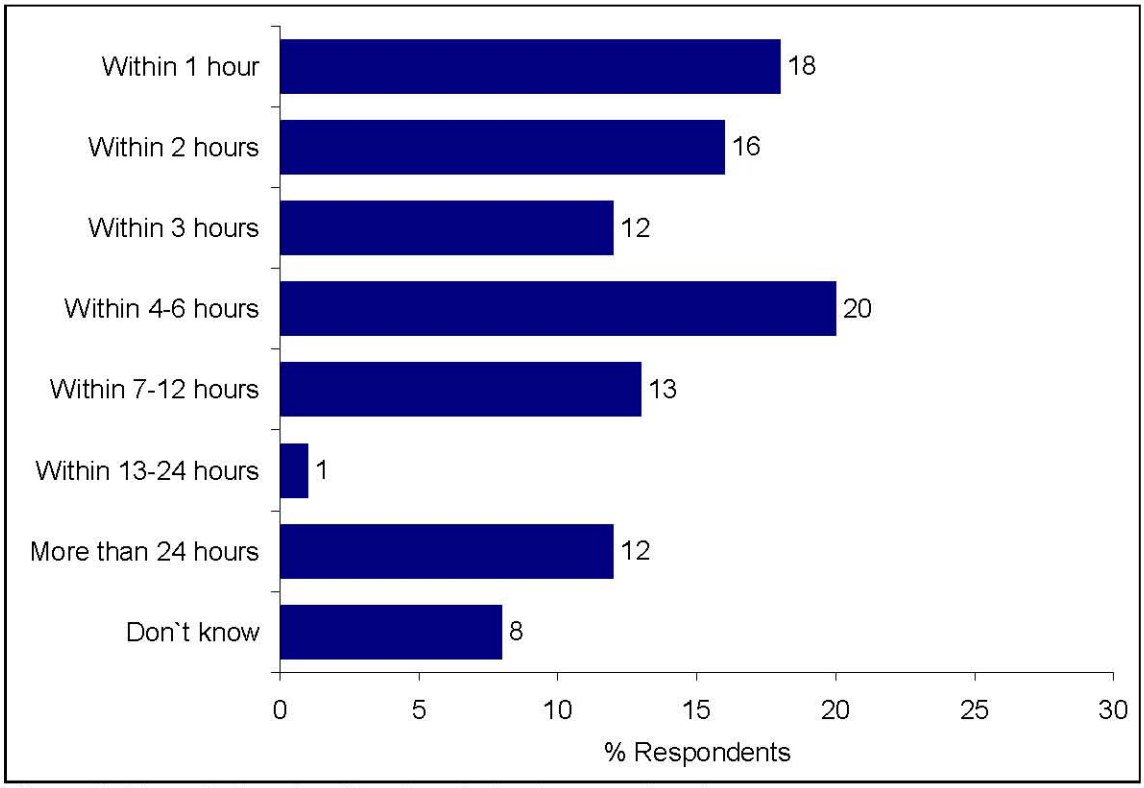


Figure 8: Expected restoration time following a major storm

In normal conditions, many consumers (44%) think power should be restored within the hour, and a further 37% expect power on within 2-3 hours.

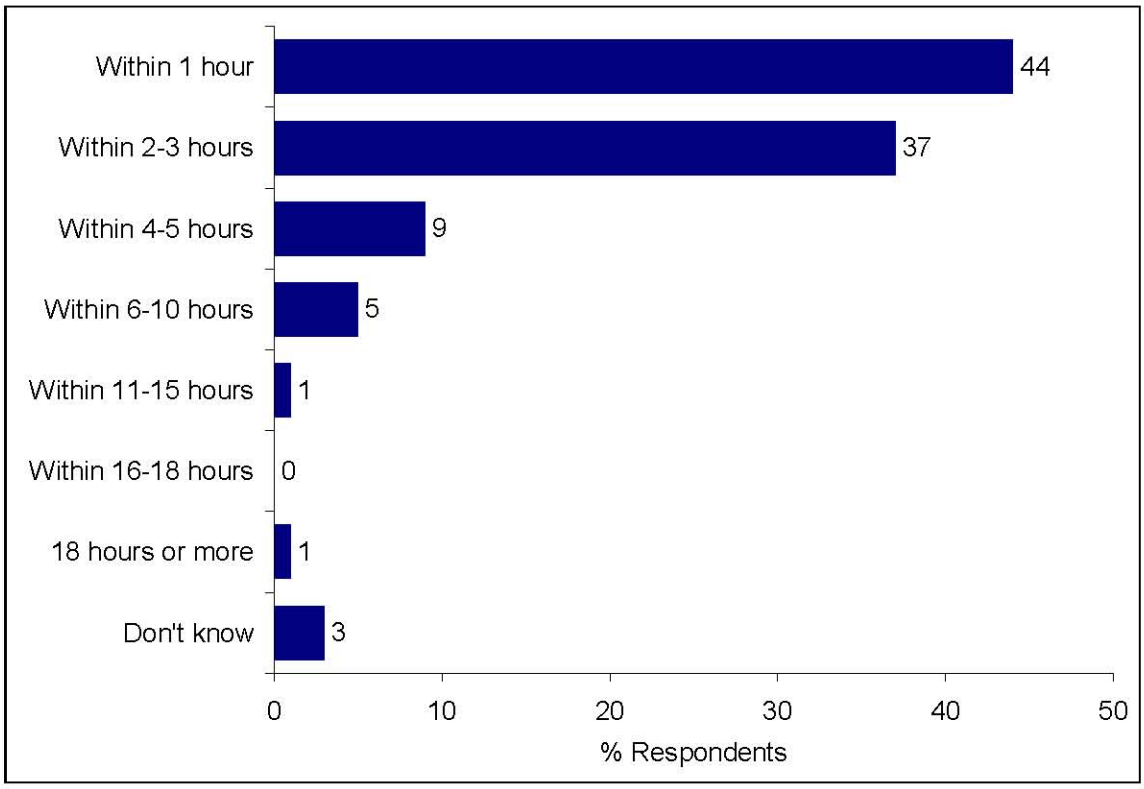


Figure 9: Expected restoration time in normal circumstances

Many domestic consumers expect compensation to be paid after a relatively short power cut. Over two-fifths think compensation should be paid for cuts shorter than 4 hours.

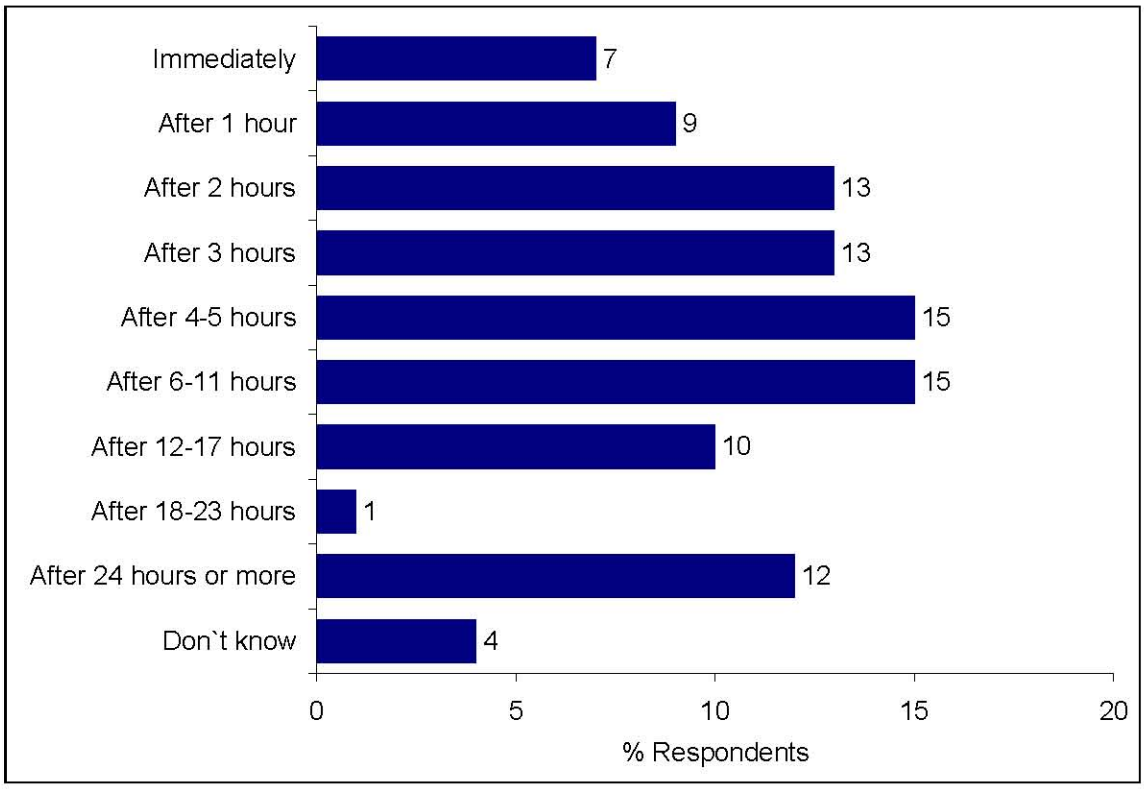


Figure 10: Number of hours cut after which distributor should be required to pay compensation in normal circumstances

Domestic consumers also have high expectations about how many cuts a distributor should be allowed before paying compensation. A tenth think compensation should be paid immediately, while a quarter think it should be paid after one cut and a further quarter after two cuts in a year.

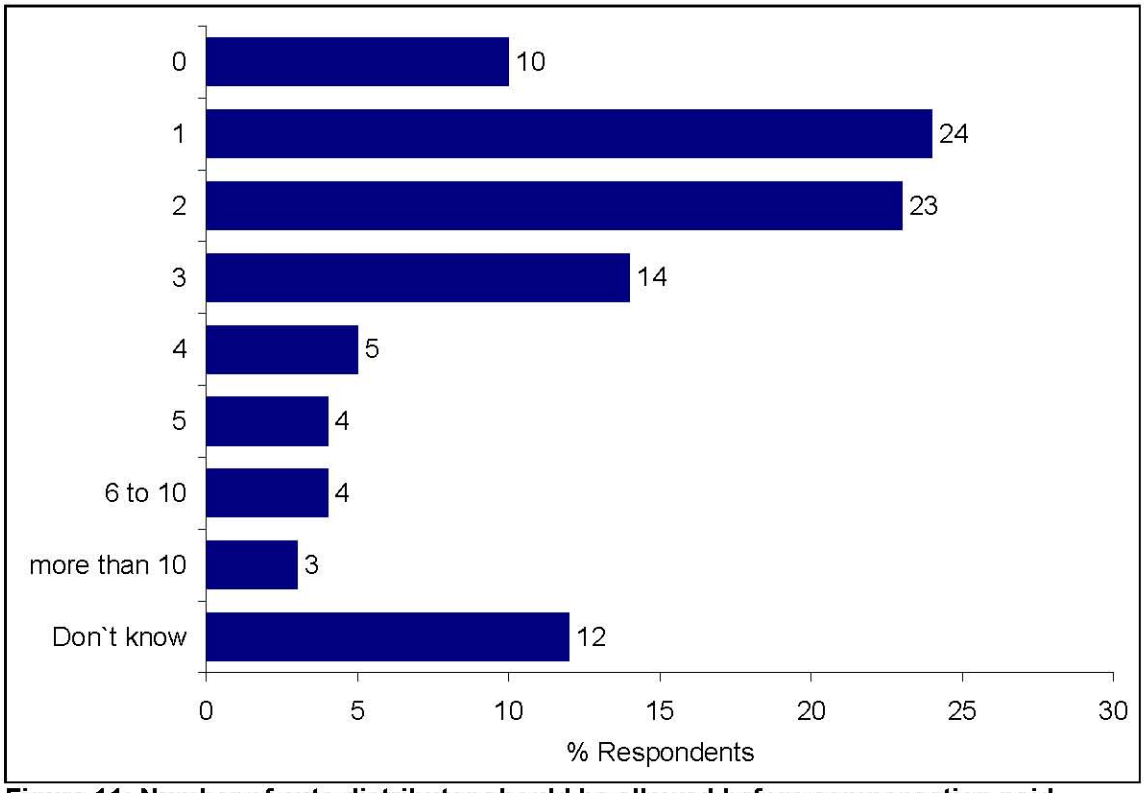


Figure 11: Number of cuts distributor should be allowed before compensation paid

4. DOMESTIC CONSUMERS' VALUATIONS OF CHANGES IN QUALITY OF SERVICE

4.1 Introduction

In the domestic segment, the stated preference analysis was conducted using real values, and therefore the primary output of the valuations is in the number of pounds consumers are willing to pay. These values refer to the additional amount consumers are willing to see on their total bill for year one and subsequent years of the improvement programme. For ease of comparison, tables below also show the values in terms of percentages of the average bill for the relevant segment.

4.2 Change in Number and Duration of Power Cuts

Both rural and urban consumers were asked to place a value on changes in the number of rural cuts and on the number of urban cuts, from the current average number of cuts over 5 years. Consumers place value on service changes in their own type of area, but show no willingness to pay for improvements in other types of area.

A range of improvements to service (reduction from the current average by one or two cuts over 5 years) and decrements to service (increase in the average) were tested. Consumers' willingness to pay for a reduction in average cuts is the same as their willingness to accept for an increase in average cuts. The values shown in the table below show a value per unplanned cut that can be applied to both improvements and decrements in service.

Rural and urban consumers are both willing to pay a similar amount, of about £20, for each cut that is reduced in their own area. The overall average for rural cuts is lower reflecting the relative number of rural consumers in the sample.

Table 19: Change in the number of power cuts

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Value per unplanned rural cut (reduction in frequency over 5 years from current)	20.04	5.2	0	0	4.35	1.2
Value per unplanned urban cut (reduction in frequency over 5 years from current)	0	0	18.45	5.2	14.59	4.0

Using consumers' relative ratings of their attitudes towards planned and unplanned cuts, the values for unplanned cuts above can be scaled to provide values for planned cuts. Consumers rated their unhappiness with the two different types of cuts as shown in the figures below.

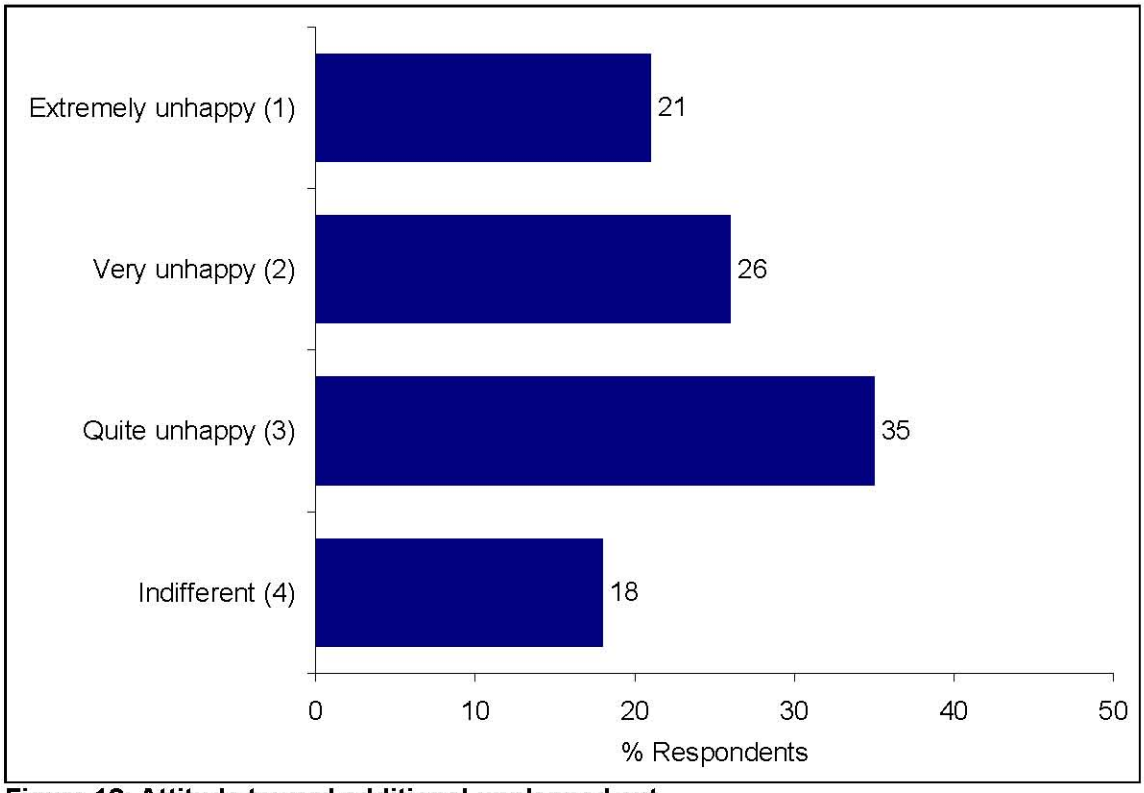


Figure 12: Attitude toward additional unplanned cut

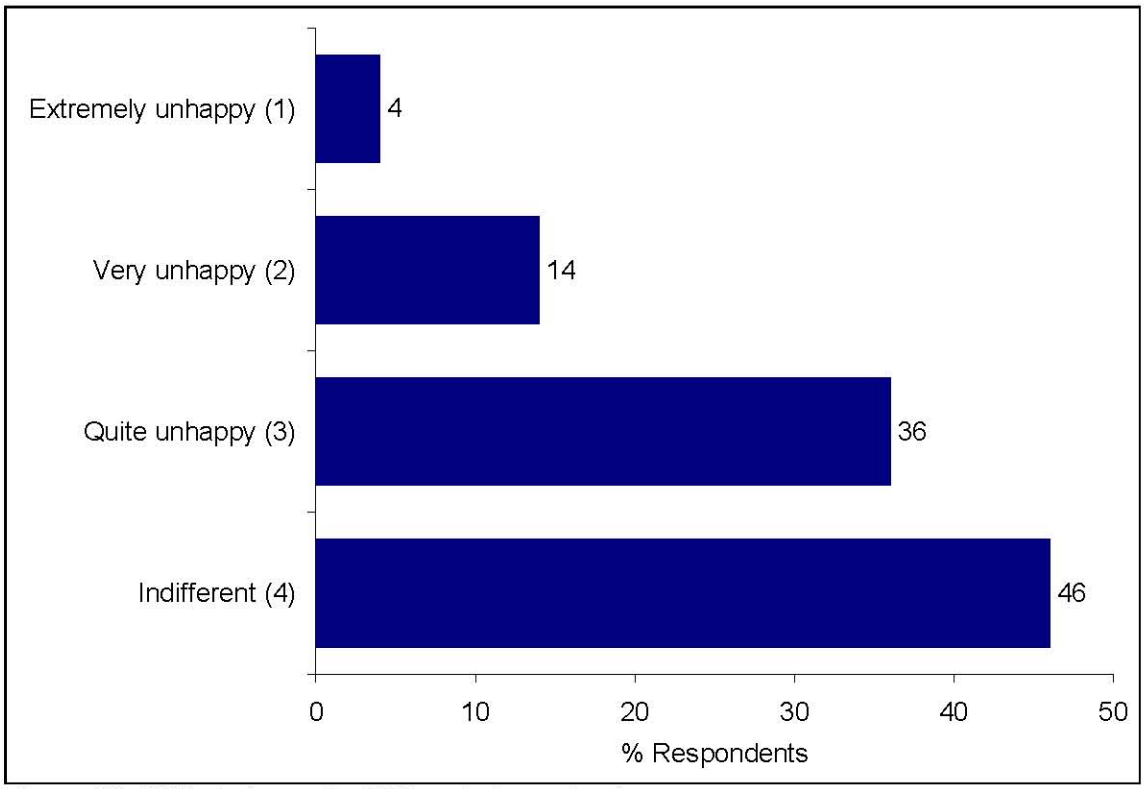


Figure 13: Attitude toward additional planned cut

The values for planned cuts are approximately half those for unplanned cuts, reflecting less inconvenience.

Table 20: Change in the number of planned power cuts

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Value per **unplanned rural** cut (reduction in frequency over 5 years from current)	20.04	5.2	0	0	4.35	1.2
Value per **planned rural** cut	11.02	2.9	0	0	2.26	0.6
Value per **unplanned urban** cut (reduction in frequency over 5 years from current)	0	0	18.45	5.2	14.59	4.0
Value per **planned urban** cut	0	0	9.28	2.6	7.59	2.1

The overall values for urban and rural cuts can be used to calculate a range of values for willingness to pay for reduction in cuts overall. The proportion of consumers in rural areas is 35% and those in urban areas 65%. To achieve an overall reduction of one cut per consumer nationally by targeting rural consumers a total of 2.86 cuts per rural consumer would be necessary, while to achieve the overall reduction by targeting urban areas would require a total of 1.54 cuts per urban consumer. Willingness to pay for these levels of improvement is shown below.

Table 21: Range of WTP to achieve reduction in cuts overall

	Proportion consumers (%)	WTP for one cut over 5 yrs	# cuts required to achieve national average of 1	WTP to achieve average cut of 1
Rural	35	£ 4.35	1/0.35=2.86	£ 12.43
Urban	65	£ 14.59	1/0.65=1.54	£ 22.45

Consumers' willingness to pay for an improvement in service in terms of reducing the average length of power cuts is also equivalent to the willingness to accept for increasing length of power cuts. The values for this service change can therefore also be applied to both improvements and decrements in service. Rural consumers are willing to pay slightly more than urban consumers to reduce the length of power cuts.

Table 22: Change in duration of power cuts

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Value per minute reduction to average cut	1.31	0.3	0.79	0.2	1.09	0.3
Value of 20 minute reduction to average cut	24.20	6.0	15.80	4.9	21.80	6.0
Value of 40 minute reduction to average cut	48.40	12.0	31.60	9.8	43.60	12.0

4.3 Improvements in Resilience of Network and Restoration After Major Storms

Significant improvements in network resilience (moving from a major event every year to one every 2 years) are only valued by rural consumers (about £6.50). A major step change in resilience (moving from one event a year to one every 5 years) would be highly valued by both urban and rural consumers (about £14). However, improvements in resilience are generally valued significantly less than quicker restoration times following major events.

Table 23: Value of improvement in resilience of network

	Rural		Urban		Total	
Reduce major cuts from one a year to:	£	% av bill	£	% av bill	£	% av bill
1 every 2 years	6.47	1.7	0	0	0	0
1 every 5 years	13.95	3.6	14.15	4.0	14.13	3.9

Improvements in maximum restoration times are very highly valued by both rural and urban consumers. Reducing the maximum restoration time to 36 hours from the current level of 48 hours is valued at about £20 by rural consumers and £15 by urban consumers. A maximum restoration time of only 24 hours is even more highly valued by rural consumers (£30); urban consumers show a smaller increase in valuation, to £19. Consumers would require a high level of compensation for longer restoration times; consumers on average would expect a £14 reduction in their total bill if maximum restoration times were to increase to 60 hours, with rural consumers requiring almost twice as much as urban consumers (£21 compared with £11).

Table 24: Value of change in maximum restoration time

	Rural		Urban		Total	
Change from current (48 hrs) to:	£	% av bill	£	% av bill	£	% av bill
Within 36 hours (improvement)	19.73	5.1	14.43	4.1	16.02	4.4
Within 24 hours (improvement)	30.14	7.9	18.59	5.3	21.89	6.0
Within 60 hours (decrement)	-21.04	-5.5	-10.70	-3.0	-13.61	-3.7

4.4 Information Provision

Although few consumers currently contact their distributor during a power cut, and those who do are generally happy with the quality of information they receive, consumers place a high value on improving the quality of information available to ensure it is accurate. Updating the information every 2 hours is valued at £22 on average, with urban consumers placing a higher value on this than rural consumers (£25 compared with £19). Since most domestic consumers do not even attempt to obtain this information when experiencing a cut, a value of £22 for improvements in accuracy may seem high. It may be that the context of the interview, covering major power cuts as well as typical events, caused consumers to value information more highly. There may also be an implication that the information currently available is not accurate. Consumers do not value the idea of receiving on request callbacks from the distributor to update on the power cut. They show some altruism in being prepared to pay around £10 per year to provide a helpline for those dependent for electricity on medical equipment.

Table 25: Valuation of improvements in information

	Rural		Urban		Total	
Additions to current provision	£	% av bill	£	% av bill	£	% av bill
Updated every 2 hours	18.74	4.9	24.98	7.1	22.03	6.0
Callbacks if required	0	0	0	0	0	0
Helpline	10.70	2.8	10.05	2.9	10.47	2.9

4.5 Compensation

Consumers see little value in tightening the multiple interruption standard so that payments are made after 3 rather than 4 cuts. However, they would require high levels of discount to compensate them for a relaxation of the standard so that payments are made after 5 cuts. The expected discount is particularly large for rural consumers.

Changing the compensation standards so that compensation under the 18 hour standard is automatic, but other standards have to be claimed, is not valued by consumers. Urban consumers place some value, of about £5, on having automatic compensation under all the standards.

Table 26: Valuation of Changes in Compensation Arrangements

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Compensation after 3 cuts (improvement)	0	0	1.10	0.3	0	0
Compensation after 5 cuts (decrement)	-28.63	-7.5	-17.53	-5.0	-20.91	-5.7
Automatic compensation for 18hr standard only	0	0	0	0	0	0
Automatic compensation for all standards	0	0	5.20	1.5	5.33	1.5

4.6 Undergrounding of the Network

Both urban and rural consumers value the undergrounding of the network in national parks and other places of outstanding natural beauty.

Table 27: Valuation of Undergrounding of Network for Aesthetic Reasons

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Per % of network per annum	2.63	0.7	2.18	0.6	2.42	0.7

4.7 Summary of Improvement Priorities

All aspects of service tested are shown in the tables below, in order of overall value.

Table 28: Summary: Priorities Between Maintaining Current Services

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
Compensation after 5 cuts (decrement)	-28.63	-7.5	-17.53	-5.0	-20.91	-5.7
Restoration within 60 hours (decrement)	-21.04	-5.5	-10.70	-3.0	-13.61	-3.7

Table 29: Summary: Priorities Among Improvement to Services

	Rural		Urban		Total	
	£	% av bill	£	% av bill	£	% av bill
40 minute reduction to average cut	48.40	12.0	31.60	9.8	43.60	12.0
Information updated every 2 hours	18.74	4.9	24.98	7.1	22.03	6.0
Restoration within 24 hours (improvement)	30.14	7.9	18.59	5.3	21.89	6.0
20 minute reduction to average cut	24.20	6.0	15.80	4.9	21.80	6.0
Restoration within 36 hours (improvement)	19.73	5.1	14.43	4.1	16.02	4.4
Value per unplanned urban cut (reduction in frequency over 5 years from current)	0	0	18.45	5.2	14.59	4.0
Reducing major outages to 1 every 5 years	13.95	3.6	14.15	4.0	14.13	3.9
Helpline	10.70	2.8	10.05	2.9	10.47	2.9
Automatic compensation for all standards	0	0	5.20	1.5	5.33	1.5
Value per unplanned rural cut (reduction in frequency over 5 years from current)	20.04	5.2	0	0	4.35	1.2
Undergrounding, per % of network per annum	2.63	0.7	2.18	0.6	2.42	0.7
Value per minute reduction to average cut	1.31	0.3	0.79	0.2	1.09	0.3
Reducing major outages to 1 every 2 years	6.47	1.7	0	0	0	0
Callbacks during power cut if required	0	0	0	0	0	0
Compensation after 3 cuts (improvement)	0	0	1.10	0.3	0	0
Automatic compensation for 18hr standard only	0	0	0	0	0	0

4.8 Regional Analysis

The domestic data did not support segmentation to the level of the individual DNOs' areas. Models showed excessive variability and a large number of insignificant terms. The reason would appear to be that the domestic data set is made up of a number of different segments, each with priorities very different from each other. This is most clearly seen in the case of the rural/urban split, where these two groups have completely opposing priorities in terms of reducing number of cuts in urban and rural areas. In the

overall data set the sample numbers are high enough to produce very significant results even when rural and urban consumers are analysed together. However, the explanatory power of the models, as indicated by the proportion of variance explained (Rho squared) is greatly improved when these two groups are analysed separately, giving separate urban and rural results.

This indicates that the results are much more consistent within the rural and urban segments than for the overall data set. Analysis at the overall DNO level does not provide good results because the sample sizes are relatively small, but still contain the high levels of diversity of priorities found in the overall data set. Unfortunately, further segmentation of each DNO by rural/urban did not improve this, because by this time the sample sizes are too small to produce adequate models. The inability to provide individual DNO models is a function of the degree of variation in consumer priorities, but the overall models are based on a data set large enough to provide robust and significant results.

The DNO areas were therefore combined into four areas for regional analysis, as follows:

- Region 1: WPD South West, WPD South Wales, SP Manweb
- Region 2: EDF Energy Networks (EPN), EDF Energy Networks (SPN), Southern
- Region 3: Central Networks (West), Central Networks (East), YEDL, NEDL, UU
- Region 4: Scottish Power, Scottish Hydro.

EDF Energy Networks (EDF Energy Networks (LPN)) was analysed completely separately as it had its own design.

Region 4 still failed to produce a satisfactory model but the other regions did produce results as shown below. The regions are fairly consistent but the most striking difference is the much higher willingness to pay of Region 3 for improvements in information. Consumers in the NEDL region, which is included in Region 3, were much more likely to indicate that they failed to get through to the distributor if they attempted to contact them during a power cut; 60% of those who tried, said that they failed, compared to between 3% and 23% of other DNOs. There may be a general dissatisfaction with information provision in this region. But the sample size is very small (n=38) and it seems unlikely that this could be driving this difference entirely.

Table 30: Regional variation in WTP values

Variable	Region 1 % of bill	Region 2 % of bill	Region 3 % of bill	EDF Energy Networks (LPN) % of bill	Total % of bill
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0.8	1.2	0.8	N/A	1.2
Value per unplanned urban cut (reduction in frequency over 5 years from current)	2.2	4.1	4.3	4.8	4.0
Value per minute reduction to average cut	0.2	0.3	0.3	0.2	0.3
Reducing major cuts to 1 every 2 years	0.0	0.0	0.0	N/A	0.0
Reducing major cuts to 1 every 5 years	3.0	3.8	4.9	N/A	3.9
Information during outage updated every 2 hours	5.5	3.7	11.0	N/A	6.0
Call backs during outage if required	0.0	0.0	0.0	N/A	0.0
Helpline	3.6	1.9	2.8	N/A	2.9
Undergrounding (per % per year)	0.9	1.2	0.0	0.0	0.7
Maximum restoration time 60 hours (decrement)	-2.6	-3.6	-3.9	N/A	-3.7
Maximum restoration time 36 hours (improvement)	3.5	5.6	4.6	N/A	4.4
Maximum restoration time 24 hours (improvement)	4.6	7.7	6.2	N/A	6.0
Compensation paid after 5 cuts (decrement)	-4.2	-7.0	-5.7	0.0	-5.7
Compensation paid after 3 cuts (improvement)	0.0	0	0.4	0.0	0.0
Automatic compensation for all standards	1.5	0.0	1.8	N/A	1.5

Region 1: WPD South West, WPD South Wales, SP Manweb
Region 2: EDF Energy Networks (EPN), EDF Energy Networks (SPN), Southern
Region 3: Central Networks (West), Central Networks (East), YEDL, NEDL, UU

4.9 Domestic Confidence Limits

Confidence intervals cannot be obtained for willingness-to-pay (WTP) values directly, because each value is derived from at least three, sometimes four or more, different coefficients. But the upper and lower confidence limits of the coefficients can be used to derive an upper and lower value of willingness to pay. Normally, we can state with 95% confidence that the coefficient lies between +/-1.96*standard error (s.e.) of the coefficient. So, to derive the lower value, a WTP is calculated using all coefficients in the calculation 1.96 * s.e. lower than the central values. For the upper, all coefficients in the calculation are 1.96 * s.e. higher than the central values. Upper and lower WTP values are not necessarily equidistant from the central values because of the complexity of the calculations.

Table 31: Domestic WTP confidence limits

Variable	WTP (£)	Lower limit	Upper limit	WTP (% of bill)	Lower limit	Upper limit
Value per unplanned rural cut (reduction in frequency over 5 years from current)	4.35	2.97	6.25	1.2	0.8	1.7
Value per unplanned urban cut (reduction in frequency over 5 years from current)	14.59	11.51	19.19	4.0	3.2	5.3
Value per minute reduction to average cut	1.09	0.93	1.35	0.3	0.3	0.4
Reducing major cuts to 1 every 2 years	0.00	0.00	0.00	0.0	0.0	0.0
Reducing major cuts to 1 every 5 years	14.13	10.52	19.56	3.9	2.9	5.4
Information during outage updated every 2 hours	22.03	20.72	25.23	6.0	5.7	6.9
Call backs during outage if required	0.00	0.00	0.00	0.0	0.0	0.0
Helpline	10.47	6.73	15.78	2.9	1.8	4.3
Undergrounding (per % per year)	2.42	1.86	3.28	0.7	0.5	0.9
Maximum restoration time 60 hours (decrement)	-13.61	-12.04	-16.20	-3.7	-3.3	-4.4
Maximum restoration time 36 hours (improvement)	16.02	14.17	19.06	4.4	3.9	5.2
Maximum restoration time 24 hours (improvement)	21.89	19.36	26.05	6.0	5.3	7.1
Compensation paid after 5 cuts (decrement)	-20.91	-18.49	-24.88	-5.7	-5.1	-6.8
Compensation paid after 3 cuts (improvement)	0	0	0	0	0	0
Automatic compensation for all standards	5.33	4.71	6.34	1.5	1.3	1.7

4.10 Effect of External Events on Valuations

During the fieldwork, a BBC TV programme called *If... the Lights Go Out,* broadcast on 10th March, dramatised a countrywide major power cut. At around the same date, a Trade and Industry Select Committee report was issued on the resilience of the networks. To test if these events might have affected response to the survey, the data set was split into two parts, those who had been interviewed before 10 March and those who had been interviewed after, and their valuations were compared. A total of 447 interviews were conducted before 10th March and 1517 after that date.

Although some values from the second part of the sample are higher, the differences are minimal and generally fall within the ranges derived from the 95% confidence limits, so it cannot be concluded that there is a difference in the values of those interviewed before and after the date.

Table 32: Effect of External Events on Valuations

Variable	'Before' (£)	'After' (£)	Total (£)
Value per unplanned rural cut (reduction in frequency over 5 years from current)	3.45	4.73	4.35
Value per unplanned urban cut (reduction in frequency over 5 years from current)	14.70	14.50	14.59
Value per minute reduction to average cut	0.89	1.16	1.09
Reducing major cuts to 1 every 2 years	0.00	0.00	0.00
Reducing major cuts to 1 every 5 years	12.51	14.63	14.13
Information during outage updated every 2 hours	19.12	22.84	22.03
Call backs during outage if required	0.00	0.00	0.00
Helpline	8.53	11.11	10.47
Undergrounding (per % per year)	3.06	2.18	2.42
Maximum restoration time 60 hours (decrement)	13.14	15.02	-13.61
Maximum restoration time 36 hours (improvement)	15.24	17.72	16.02
Maximum restoration time 24 hours (improvement)	19.97	24.75	21.89
Compensation paid after 5 cuts (decrement)	-18.53	-23.65	-20.91
Compensation paid after 3 cuts (improvement)	0.26	0	0
Automatic compensation for all standards	5.87	0.00	5.33

It is possible that consumers' valuations are affected by other external events, such as the major power cuts that took place in both New York and London before this project started, and which were covered extensively in the media, or the power cuts that took place in the North and Scotland following severe weather over the New Year, but there is no way to test this using the data.

5. BUSINESS CONSUMERS' EXPERIENCE AND ATTITUDES

Please note that numbers in tables and figures may not add to 100% due to rounding.

5.1 Size of Organisations

The percentage of business consumers with large (over £159,000 per annum), medium (£15,000 to £159,000 per annum) and small (less than £15,000) bills is shown for each DNO below.

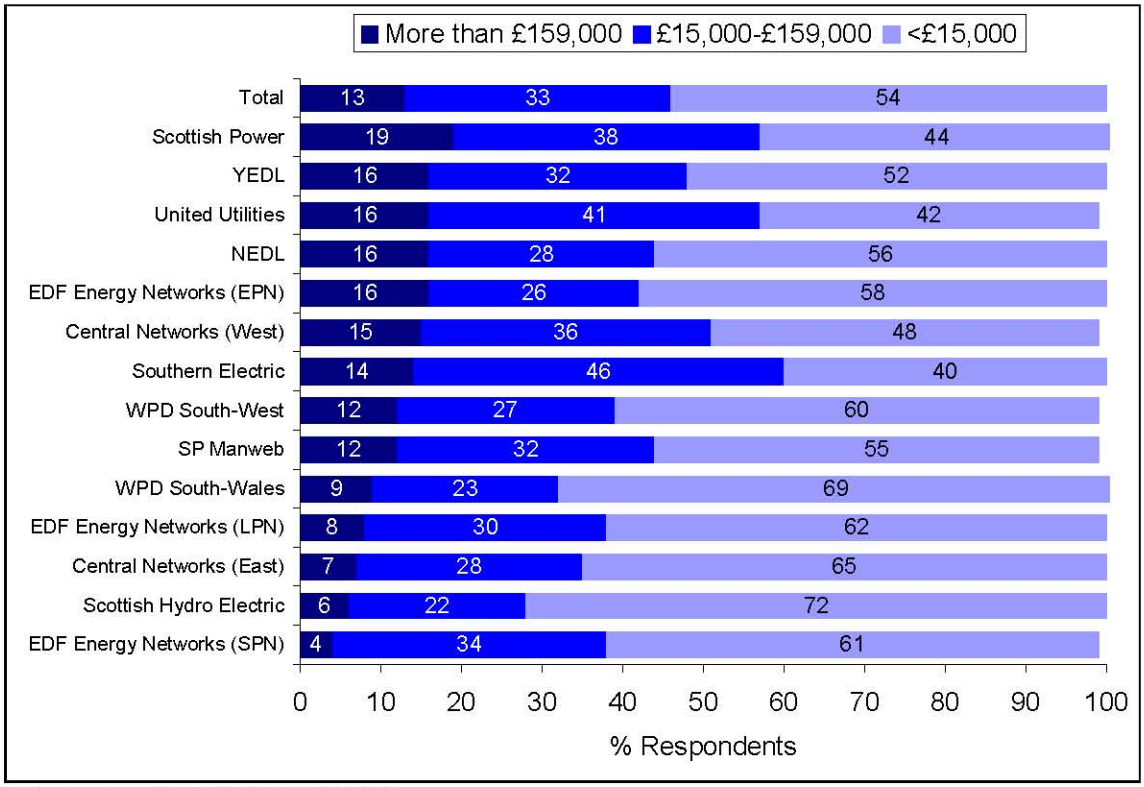


Figure 14: Size of Organisation

5.2 Experience of Outages

Large organisations are slightly less likely to report that they have experienced an unplanned power cut in the last 12 months; 40% of large organisations say they have done so, compared with 46% of both medium and small companies.

Frequent cuts are rare; most of those who have experienced cuts say they have had only one or two in the year.

Small organisations are more likely to experience more frequent and longer unplanned cuts than larger ones, as shown in the figures below.

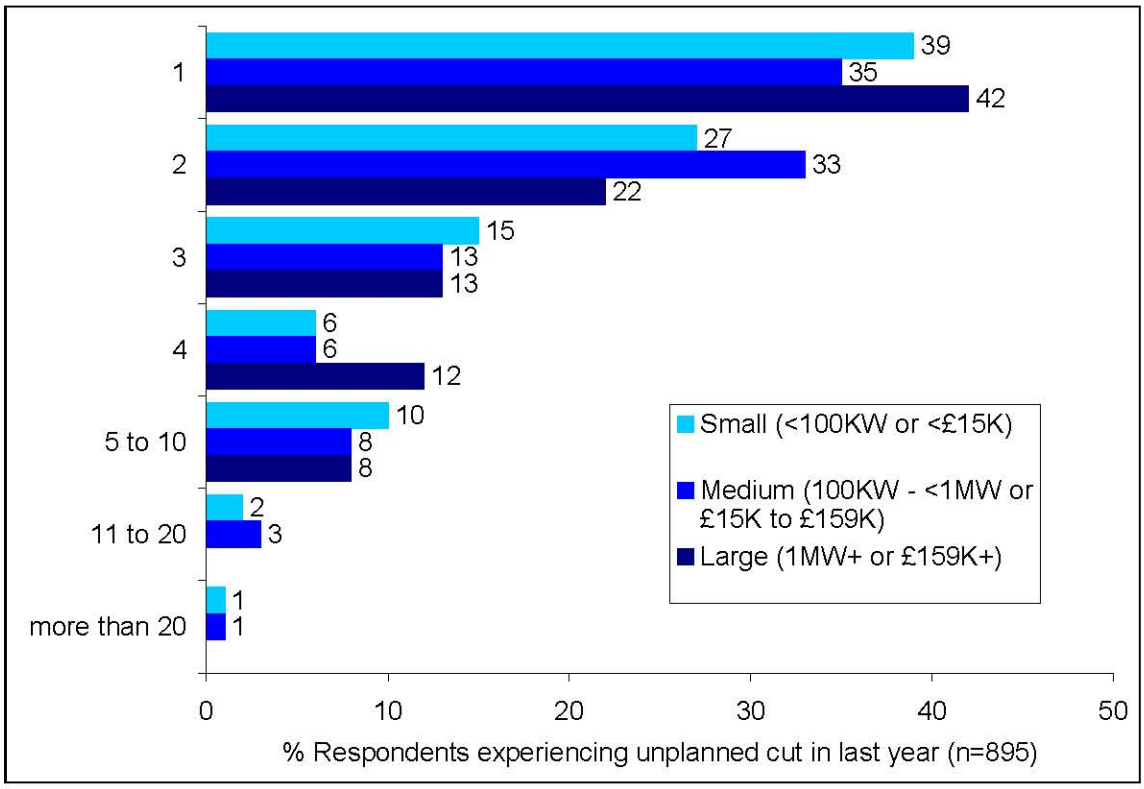


Figure 15: Frequency of unplanned cuts in past year

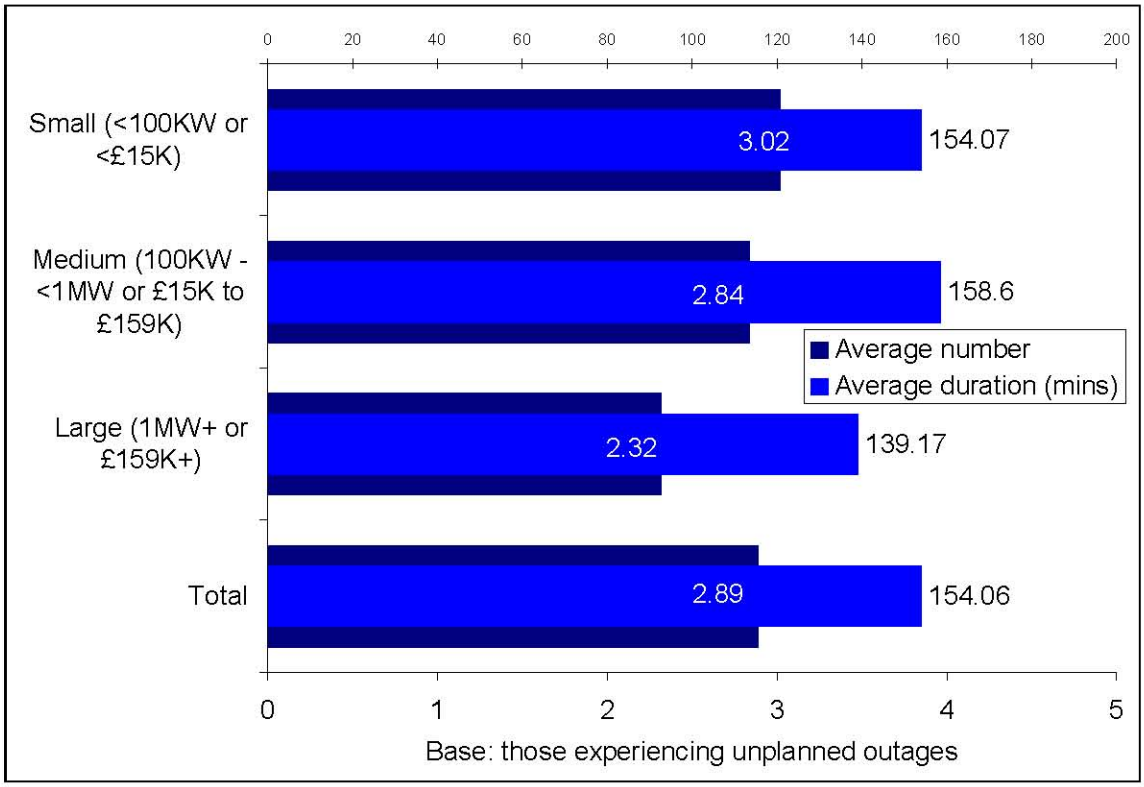


Figure 16: Average frequency and duration of unplanned cuts in past year

Around one in ten (10%) of business consumers have experienced a planned power cut in the past year. Generally they only experienced one planned cut (75% had only one cut) but the average duration is slightly longer at 177 minutes.

5.3 Experience of Contacting Distributor During Power Cut

Business consumers are much more likely to contact their distributor during an unplanned power cut than domestic consumers. Of the 62% who attempted to get through, the vast majority were successful (86%). Generally the perceived response time is fast, with almost one third (31%) stating that their calls were answered within 10 seconds.

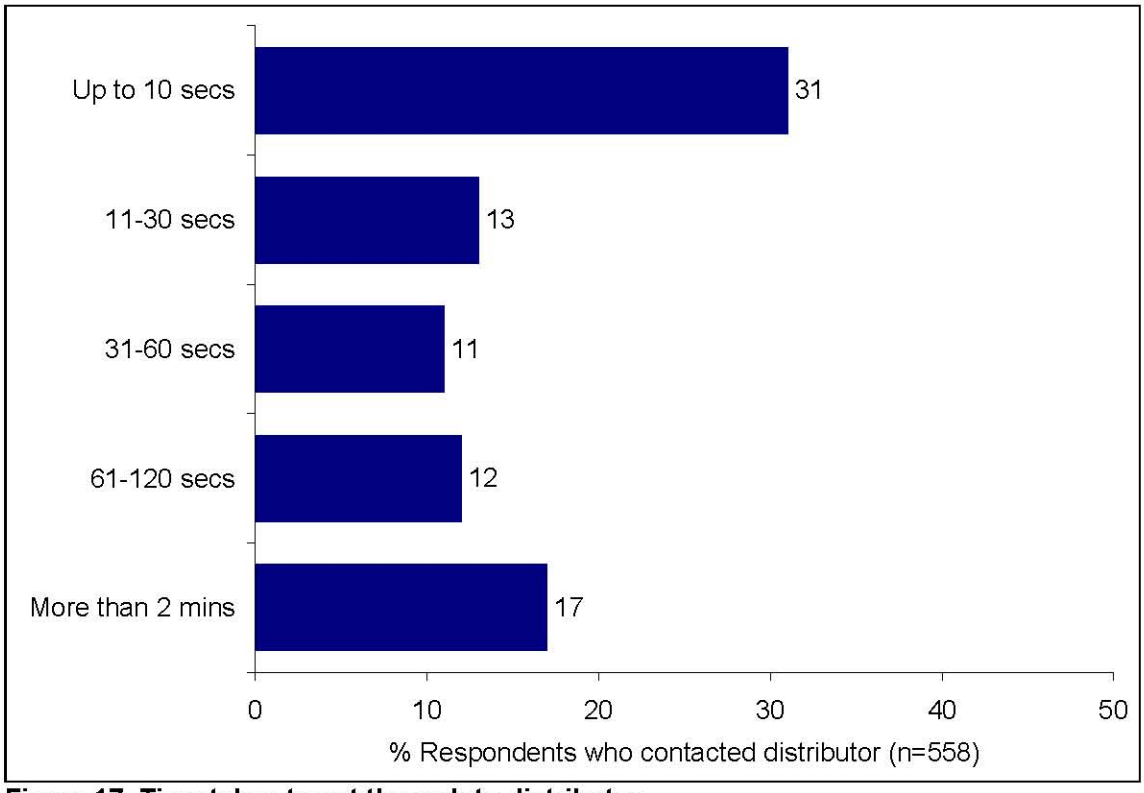


Figure 17: Time taken to get through to distributor

About a third of those who contacted their distributor received an automated response and a further third spoke to someone (the remainder did both or could not remember). Most business consumers get the information they want (69%) and the vast majority find the information they receive is correct (87%). Those who spoke to someone are more likely to say they got the information they wanted, but there is only a small difference in the accuracy of the information between speaking to a person and an automated response.

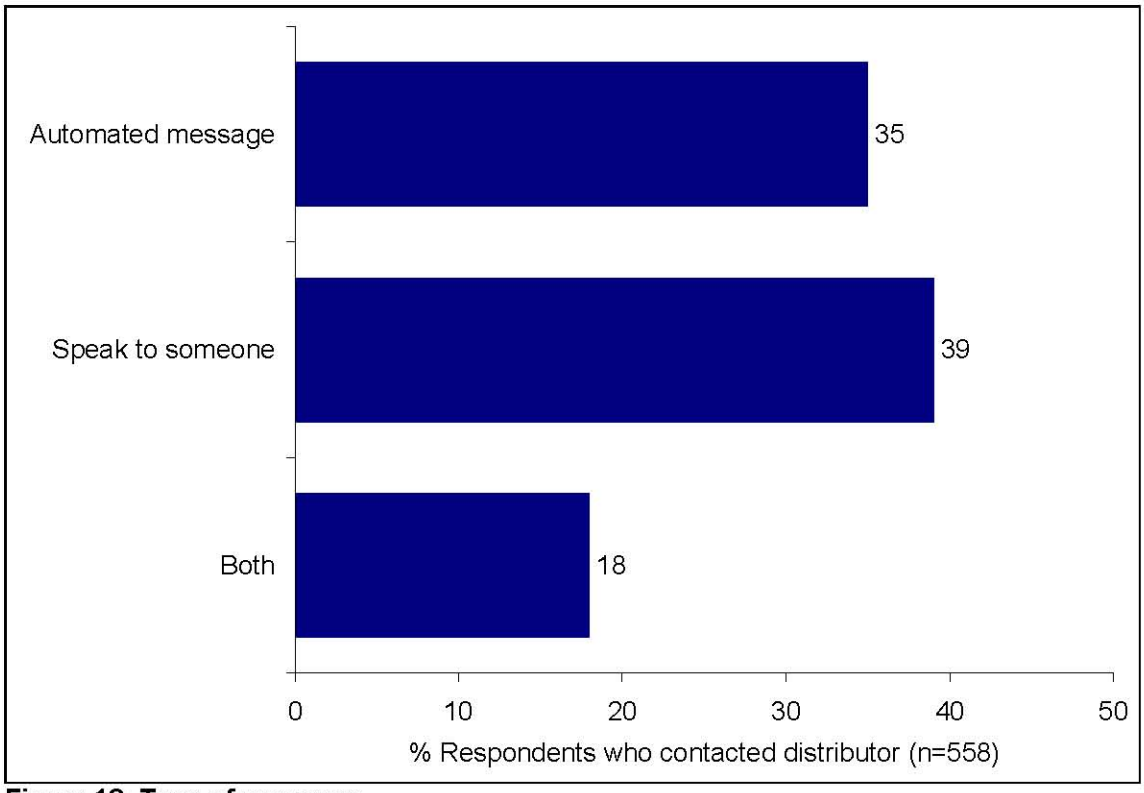


Figure 18: Type of response

Table 33: Quality of Information by Type of Response

	Type of response			Total %
	Automated message %	Spoke to someone %	Both %	
Got the information they were looking for	64	75	71	69
Information was correct	90	88	85	87

In general therefore businesses tend to have a positive experience when contacting their distributor during a power cut, and unlike domestic consumers are more likely to have experienced the quality of information at first hand.

5.4 Expectations of Quality of Service

Awareness of the standards and targets currently in place is low among all businesses. Larger organisations are only slightly more aware than smaller ones.

Table 34: Awareness of 18 hour restoration standard[1]

	Large %	Medium %	Small %	Total %
Aware of standard but not amount of compensation	8	10	6	8
Aware of standard and amount of compensation	10	6	4	5
Unaware of standard or compensation	83	84	90	87

[1]The definition used in the question was: "Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £100 for business consumers for the first 18 hours plus £25 for each additional 12 hours."

Table 35: Awareness of penalty payment of £50 for 4+ cuts[2]

	Large %	Medium %	Small %	Total %
Aware of standard but not amount of compensation	6	4	3	4
Aware of standard and amount of compensation	4	4	1	2
Unaware of standard or compensation	90	92	96	94

[2]The definition used in the question was: "Consumers are entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year."

Table 36: Awareness of 2 day notice standard[3]

	Large %	Medium %	Small %	Total %
Aware of standard but not amount of compensation	15	19	14	16
Aware of standard and amount of compensation	8	5	2	4
Unaware of standard or compensation	77	76	84	81

[3]The definition used in the question was: "Consumers must be given at least 2 days' notice of a planned power cut. Failure to do so results in a penalty payment of £40 for business consumers."

5.5 Expectations of Quality of Service

Business consumers have high expectations of quality of service. Although three quarters (74%) think it is reasonable for a power cut to occur in a major storm, an almost equal proportion (73%) think that distribution companies should be doing more to reduce the impact of severe weather on their networks. Like domestic consumers, businesses look for their power to be restored quickly. Even after a major storm, only one in five businesses (19%) think power should take 24 hours or more to restore. A fifth expect power to be restored within one hour even in these circumstances, and a further 26% expect it to be restored within 2 or 3 hours.

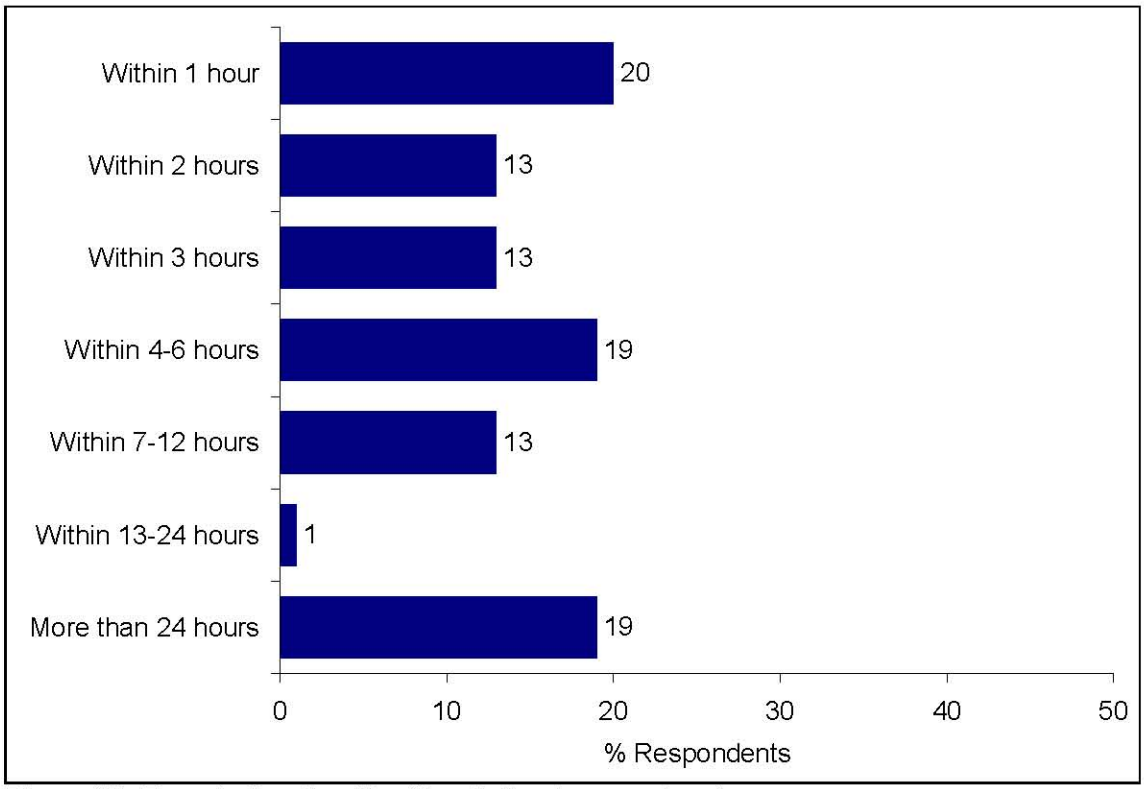


Figure 19: Expected restoration time following a major storm

In normal conditions, over half (56%) of businesses expect power to be restored within an hour.

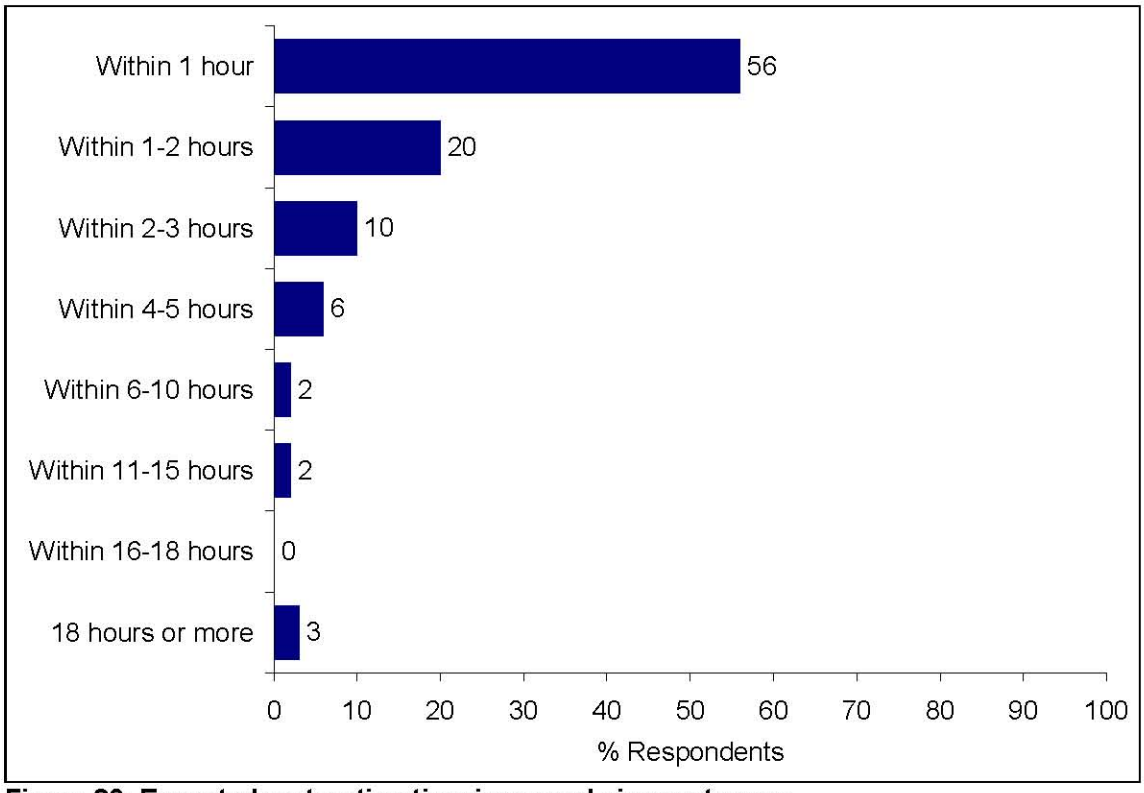


Figure 20: Expected restoration time in normal circumstances

Over a tenth (13%) of businesses believe that compensation should be paid immediately, and a fifth (21%) that it should be paid after only one hour of a power cut.

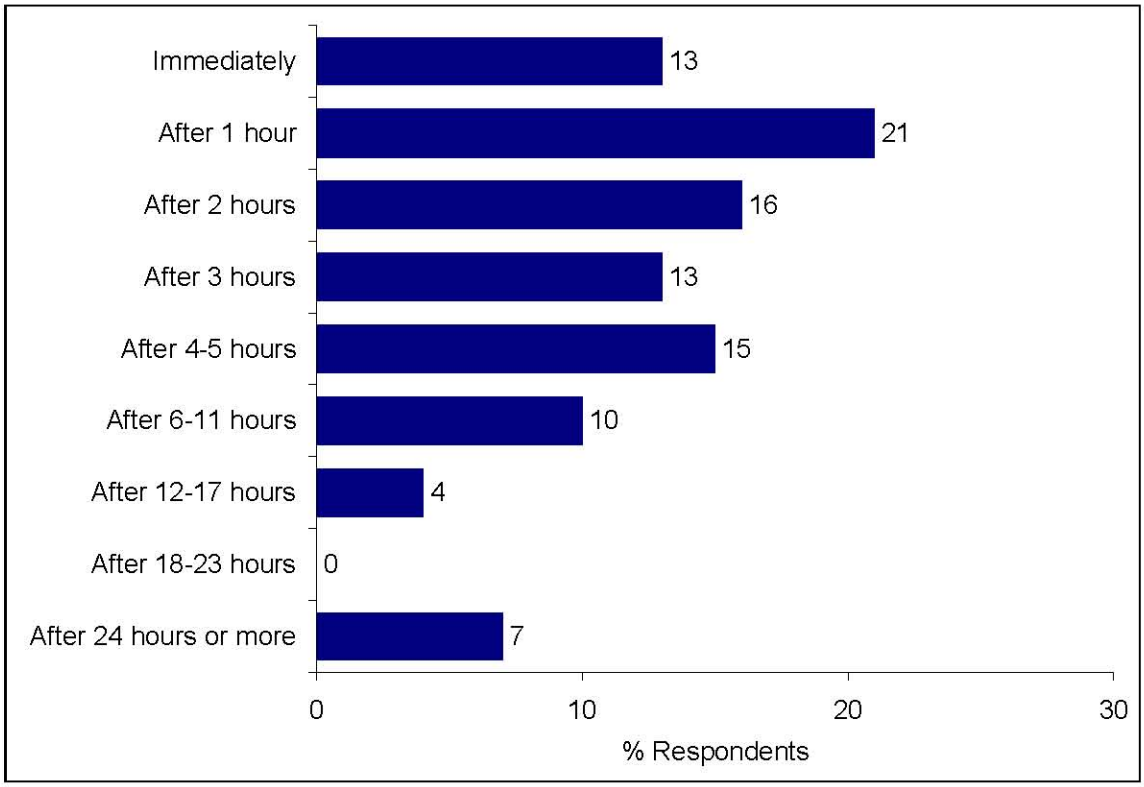


Figure 21: Number of hours after which distributor should be required to pay compensation in normal circumstances

Business consumers have very high expectations about the number of cuts distributors should be allowed before compensation starts to be paid. Over a quarter (28%) think no cuts should be allowed (i.e. compensation should be paid for the first cut in a year); a third (33%) would only be prepared to accept one cut in a year before compensation is paid.

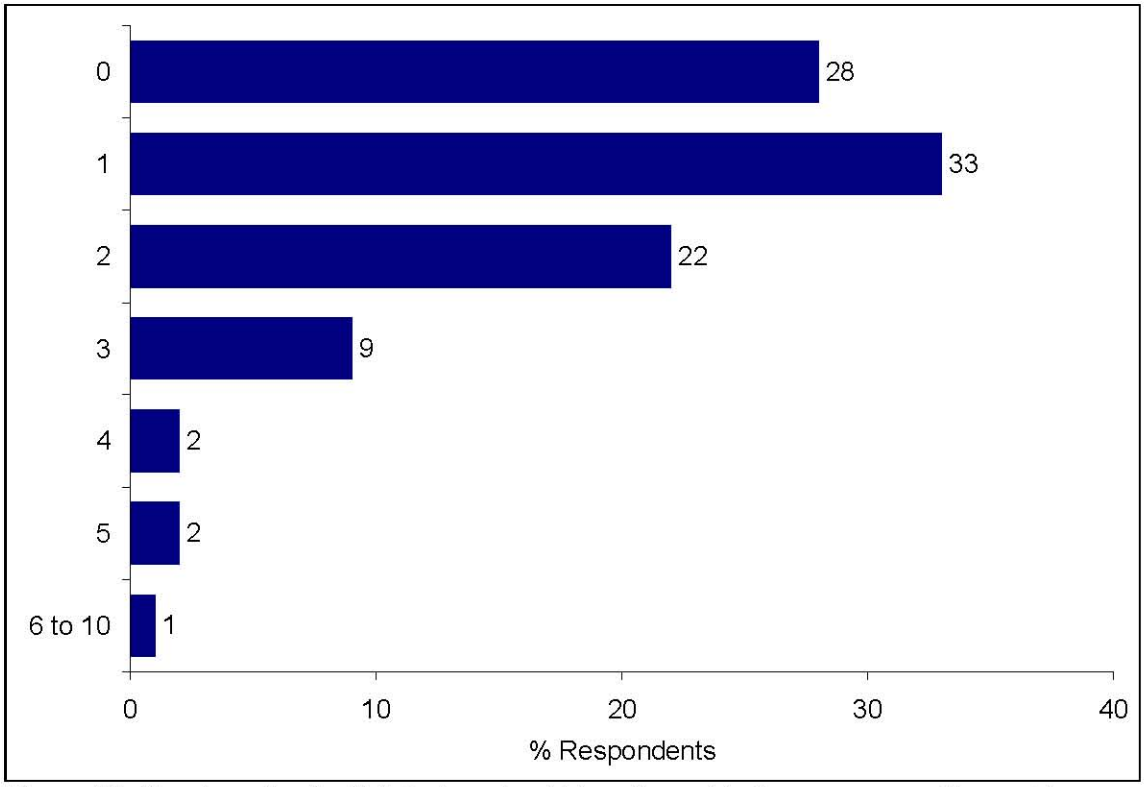


Figure 22: Number of cuts distributor should be allowed before compensation paid

6. BUSINESS CONSUMERS' VALUATIONS OF CHANGES IN SERVICE

6.1 Introduction

The stated preference analysis in the business segment was conducted using percentage values, and results are therefore shown in terms of percentage changes to their total electricity bills which businesses are willing to pay in the first and subsequent years of the improvement programme.

6.2 Change in Number and Duration of Power Cuts

All sizes of business are prepared to pay between 3 and 4% of their bill to see a reduction in frequency of power cuts in urban areas, but only medium and small companies are prepared to pay for reductions in rural areas and even then their willingness to pay is substantially less (less than 1%). Undoubtedly this reflects the location of most businesses and therefore their likelihood of being affected by the different type of cuts.

Table 37: Change in the number of power cuts

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0	0.46	0.84	0.88	0	0.54
Value per unplanned urban cut (reduction in frequency over 5 years from current)	3.58	3.93	3.06	2.43	4.95	3.52

The values for unplanned cuts were scaled using attitudinal ratings to provide values for planned cuts, as with the domestic values. While small and medium companies value planned cuts about half as much as unplanned cuts, large organisations see less differential between them, valuing a planned cut at about two thirds of an unplanned cut. The relative inconvenience is not reduced by advance notice to the same extent for large organisations.

Table 38: Change in the number of power cuts

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Value per **unplanned rural** cut (reduction in frequency over 5 years from current)	0	0.46	0.84	0.88	0	0.54
Value per **planned rural** cut (reduction in frequency over 5 years from current)	0	0.25	0.42	0.46	0	0.29
Value per **unplanned urban** cut (reduction in frequency over 5 years from current)	3.58	3.93	3.06	2.43	4.95	3.52
Value per **planned urban** cut (reduction in frequency over 5 years from current)	2.22	2.11	1.54	1.28	2.65	1.86

Using the proportion of rural and urban consumers to calculate a range of willingness-to-pay for an overall national average reduction of one cut per consumer, as before, gives the following values:

Table 39: Range of WTP to achieve cuts overall

	Proportion consumers (%)	WTP for one cut over 5 yrs	# cuts required to achieve national average of 1	WTP to achieve average cut of 1
Rural	35	0.54%	2.86	1.54%
Urban	65	3.52%	1.54	5.42%

Smaller companies place more value on reductions to the average duration of cuts than large or medium companies.

Table 40: Change in the duration of power cuts

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Value per minute reduction to average cut	0.12	0.12	0.17	0.15	0.15	0.14
Value of 20 minute reduction to average cut	2.47	2.43	3.36	2.96	3.03	2.88
Value of 40 minute reduction to average cut	4.93	4.86	6.72	5.91	6.06	5.77

6.3 Improvements in Resilience of Network and Restoration after Major Storms

Reducing the number of major cuts in the network, affecting 1% of a DNO's consumers, from an average of one per year is not valued by large organisations. They either do not expect to suffer from these events or have contingency plans in place, such as generators. However the medium and smaller organisations value significant reductions in the frequency of such major events occurring to one every 2 years at 2% and 2.85% of their final electricity bill respectively. A step change in the frequency of such events occurring to once every 5 years is highly valued at 3.41% for medium and 4.47% for small companies. However, it is still valued significantly less than quicker restoration times following major events

Table 41: Value of improvement in resilience of network

Reduce major cuts from one a year to:	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
1 every 2 years	0	2.05	2.85	2.60	1.90	2.23
1 every 5 years	0	3.41	4.47	3.96	3.24	3.60

Improving maximum restoration times after major storms is one of the most highly valued aspect of service improvement tested. Overall, an improvement from the current maximum time of 48 hours to 36 hours is valued at 3.88% of the bill; a further improvement to 24 hours is worth almost 5% (4.68%). A decrement in service, so that maximum restoration times increased to 60 hours, would require an equally large compensation; the value of such a change is – 4.27%.

Table 42: Value of change in maximum restoration time

Change from current (48 hrs) to:	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Within 36 hours (improvement)	2.90	4.12	4.25	4.14	3.92	3.88
Within 24 hours (improvement)	3.83	4.87	5.85	4.82	5.27	4.86
Within 60 hours (decrement)	-4.02	-5.51	-3.47	-4.73	-4.18	-4.27

6.4 Information Provision

It was previously noted that business consumers are much more likely than domestic consumers to have experience of contacting the distributor during a power cut, and in general are able to get through and get the information they want when they do so. Improvements to the service are therefore not likely to be required, and in fact only small companies value any improvement to the service in terms of callbacks during an outage if required (1.73%). Business consumers are not willing to pay for a dedicated business helpline. In the stage 1 survey, nine out of ten businesses said they would expect a dedicated contact line for businesses in the event of a power cut, and having a dedicated contact was rated very important by 47% (rapid restoration of power was the most important aspect in that survey, rated very important by 89%). However, the implication of the findings of this survey is that while expected and important, a dedicated helpline is not something businesses are willing to pay for.

Table 43: Valuation of Improvements in Information

Additions to current provision	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Callbacks if required	0	0	1.73	0.87	0.85	0.87
Helpline	0	0	0	0	0	0

6.5 Compensation

Business consumers place little value on tightening the multiple interruption standard so that payments are made after 3 cuts longer than 3 hours rather than 4, and nor do they require large amounts of discount to compensate them for a relaxation in this standard so that payments are made after 5 cuts.

Only small business consumers place value on an improvement in compensation arrangements; if the compensation were paid after 14 hours rather than 18, was based on the bill size rather than a fixed amount, and was paid automatically, small consumers would pay less than 1% more.

Table 44: Valuation of Changes in Compensation Arrangements

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Compensation after 3 cuts (improvement)	0	0.74	0.54	1.10	0.53	1.22
Compensation after 5 cuts (decrement)	0	0	-1.52	0	-0.89	0
Current compensation but after 14 hrs	0	0	0	0	0	0
Compensation after 14 hours based on bill size	0	0	0	0	0	0
Higher compensation and automatic	0	0	0.91	0	0	0.45

In general business consumers find the levels of compensation insufficient. Some comments were made during the interviewing such as: *"The amounts are derisory,"* and *"The rate of compensation is pointless to me, even with the higher rate."*

6.6 Summary of Improvement Priorities

Table 45: Summary: Priorities Between Maintaining Current Services

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Compensation after 5 cuts (decrement)	0	0	-1.52	0	-0.89	0
Restoration within 60 hours (decrement)	-4.02	-5.51	-3.47	-4.73	-4.18	-4.27

Table 46: Summary: Priorities Among Improvement to Services

	Size			Experience of outages		Overall % of bill
	Large % of bill	Medium % of bill	Small % of bill	Cuts % of bill	No cuts % of bill	
Value of 40 minute reduction to average cut	4.93	4.86	6.72	5.91	6.06	5.77
Restoration within 24 hours (improvement)	3.83	4.87	5.85	4.82	5.27	4.86
Restoration within 36 hours (improvement)	2.90	4.12	4.25	4.14	3.92	3.88
Reducing major cuts to 1 every 5 years	0	3.41	4.47	3.96	3.24	3.60
Value per unplanned urban cut (reduction in frequency over 5 years from current)	3.58	3.93	3.06	2.43	4.95	3.52
Value of 20 minute reduction to average cut	2.47	2.43	3.36	2.96	3.03	2.88
Reducing major cuts to 1 every 2 years	0	2.05	2.85	2.60	1.90	2.23
Compensation after 3 cuts (improvement)	0	0.74	0.54	1.10	0.53	1.22
Callbacks during outage if required	0	0	1.73	0.87	0.85	0.87
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0	0.46	0.84	0.88	0	0.54
Value per minute reduction to average cut	0.12	0.12	0.17	0.15	0.15	0.14
Higher compensation and automatic	0	0	0.91	0	0	0.45
Helpline	0	0	0	0	0	0
Current compensation but after 14 hrs	0	0	0	0	0	0
Compensation after 14 hours based on bill size	0	0	0	0	0	0

6.7 Regional Analysis

Individual DNO results were successfully obtained for the business segment and are shown in the appendices.

Regions are fairly consistent, with the most marked difference being the higher propensity of business consumers in Region 3 to value reductions in urban cuts and their negative response to increasing the maximum restoration time to 60 hours.

Table 47: Regional Variation in WTP

Variable	Region 1	Region 2	Region 3	Region 4	EDF Energy Networks (LPN)	Total (% of bill)
Value per unplanned rural cut (reduction in frequency over 5 years from current)	1.08	0.49	1.91	0.29	N/A	0.54
Value per unplanned urban cut (reduction in frequency over 5 years from current)	2.89	2.65	8.53	4.17	4.53	3.52
Value per minute reduction to average cut	0.18	0.11	0.00	0.16	0.12	0.14
Reducing major cuts to 1 every 2 years	2.71	1.54	1.61	3.07	N/A	2.23
Reducing major cuts to 1 every 5 years	4.38	3.20	2.73	4.20	N/A	3.60
Call backs during outage if required	0.00	0.80	1.04	0.80	0.00	0.87
Helpline	0.00	0.00	0.00	0.00	0.00	0.00
Maximum restoration time 60 hours (decrement)	-5.04	-3.99	-11.54	-4.02	N/A	-4.27
Maximum restoration time 36 hours (improvement)	3.87	4.61	4.96	3.77	N/A	3.88
Maximum restoration time 24 hours (improvement)	5.29	4.69	7.67	4.97	N/A	4.86
Compensation paid after 5 cuts (decrement)	0.00	-0.62	0.00	0.00	-3.4	0.00
Compensation paid after 3 cuts (improvement)	1.22	0.78	0.00	1.02	1.18	1.22
Current compensation but after 14 hrs	0.00	0.00	0.00	0.00	0.00	0.00
Compensation after 14 hours based on bill size	0.00	0.00	0.00	0.00	0.00	0.00
Higher compensation paid automatically	0.00	0.00	0.00	0.00	0.00	0.45

Region 1: WPD South West, WPD South Wales, SP Manweb
Region 2: EDF Energy Networks (EPN), EDF Energy Networks (SPN), Southern
Region 3: Central Networks (West), Central Networks (East), YEDL, NEDL, UU
Region 4: Scottish Power, Scottish Hydro.

6.8 Business Confidence Limits

These were calculated from the lower and upper 95% confidence limits of each coefficient used in the calculation of the value, as for the domestic segment.

Table 48: Business WTP confidence limits

Variable	WTP (% of bill)	Lower limit	Upper limit
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0.54	0.39	0.71
Value per unplanned urban cut (reduction in frequency over 5 years from current)	3.52	3.29	3.87
Value per minute reduction to average cut	0.14	0.12	0.17
Reducing major cuts to 1 every 2 years	2.23	2.11	2.42
Reducing major cuts to 1 every 5 years	3.60	2.73	4.67
Call backs during outage if required	0.87	0.82	0.94
Helpline	0.00	0.00	0.00
Maximum restoration time 60 hours (decrement)	-4.27	-4.19	-4.45
Maximum restoration time 36 hours (improvement)	3.88	3.81	4.04
Maximum restoration time 24 hours (improvement)	4.86	4.77	5.06
Compensation paid after 5 cuts (decrement)	0.00	0.00	0.00
Compensation paid after 3 cuts (improvement)	1.22	1.19	1.27
Current compensation but after 14 hrs	0.00	0.00	0.00
Compensation after 14 hours based on bill size	0.00	0.00	0.00
Higher compensation paid automatically	0.45	0.44	0.47

6.9 Effect of External Events on Valuations

As for domestic consumers, the business sample was divided between those interviewed prior to 10th March and those interviewed after, and their WTP values compared to see if an affect could be attributed to external events. Caution is required in drawing conclusions from these results because only a small number of interviews were conducted before 10th March. Those interviewed in the later group place a higher value on improving maximum restoration times, and these differences lie outside of the ranges calculated from the 95% confidence limits, so this may reflect a real change in values. These values are highlighted in the table below.

Table 49: Effect of External Events on WTP

Variable	'Before' n=264	'After' n=1562	WTP (% of bill)
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0.94	0.44	0.54
Value per unplanned urban cut (reduction in frequency over 5 years from current)	3.12	3.66	3.52
Value per minute reduction to average cut	0.08	0.16	0.14
Reducing major cuts to 1 every 2 years	2.40	2.23	2.23
Reducing major cuts to 1 every 5 years	3.59	3.63	3.60
Call backs during outage if required	1.91	0.68	0.87
Helpline	0.00	0.00	0.00
Maximum restoration time 60 hours (decrement)	-3.43	-4.72	-4.27
Maximum restoration time 36 hours (improvement)	3.54	4.16	3.88
Maximum restoration time 24 hours (improvement)	4.47	5.23	4.86
Compensation paid after 5 cuts (decrement)	0.00	0.00	0.00
Compensation paid after 3 cuts (improvement)	2.00	1.09	1.22
Current compensation but after 14 hrs	0.00	0.00	0.00
Compensation after 14 hours based on bill size	0.00	0.00	0.00
Higher compensation paid automatically	1.43	0.00	0.45

7. SUMMARY AND CONCLUSIONS

Business and domestic consumers both place a high priority on improvement in maximum restoration times. Domestic consumers are prepared to pay an additional £22, or 6% of the annual bill, for maximum restoration time to be reduced to 24 hours. Business consumers are prepared to pay 4.9% of the annual bill for the same improvement. Reducing maximum restoration time to 36 hours is also valued but to a lesser degree (3.9% for business, 4.4% for domestic consumers). An increase in maximum restoration times to 60 hours would be negatively regarded: domestic consumers would require a discount of £14 (3.7% of their annual bill); business consumers, 4.3% of their annual bill.

Significant improvements in network resilience are valued by some consumers but not others, but a major step change in network resilience such as major cuts being reduced to once every five years rather than once a year would be highly valued, but less so than improving restoration times. If major cuts affecting 1% of a DNO's consumers were reduced from an average of 1 per year to one every five years, business consumers would pay an additional 3.6% and domestic consumers an additional 3.9%.

Reducing the number of cuts is a high priority for consumers, but only if it affects their area. In the domestic market, both rural and urban consumers are prepared to pay around £20 for a cut avoided in their own area, but nothing towards reducing cuts elsewhere. Business consumers place much higher value on reducing urban cuts, which are likely to affect them, than on rural cuts; the average preparedness to pay is 3.5% of the bill for each urban cut avoided. The willingness to pay for reduction in rural cuts is much lower, 0.5% of their bill, and is driven mainly by small companies who are more likely to be affected by such outages.

A key priority for domestic consumers is to ensure that they receive accurate information during a power cut. Although most domestic consumers who experience a cut do not contact their distributor, and those who do have a relatively satisfactory experience, willingness to pay to ensure that information is updated every two hours to ensure accuracy is high. Domestic consumers are prepared to pay £22, or 6% of their total bill, for this improvement. This seems a high value for a service that most domestic consumers do not bother to use, and may be due to the implicit assumption in the evaluation that if it is not updated in this way the information they are given will not necessarily be accurate. There is no willingness to pay for a callback service. Domestic consumers show some altruism in being prepared to pay an additional 3% to pay for a helpline for consumers medically dependent on electrical equipment.

Most business consumers do not require improvements to information; only small companies show interest in a callback service, and their value is relatively low (1.7%). There is no value attached to a dedicated business helpline, possibly because business consumers are more likely to have experience of contacting their distributor during a power cut and almost all are able to get through and receive accurate information in a satisfactory amount of time.

Domestic and business consumers also highly value a reduction in the duration of power cuts. Reducing the average power cut by 40 minutes would be valued more highly than any other improvement by both domestic and business consumers. For domestic consumers, this improvement would be valued at £43.60, or 12% of the bill. A

reduction in the average length of cuts of 20 minutes would be valued at an equivalent level to the other two main domestic priorities, improving restoration times to 24 hours or to improving accurate information. For business consumers reducing average cut length by 40 minutes is valued at 5.8%, higher than the improvement of restoration times to 24 hours, while a reduction of 20 minutes is valued at 2.8%, slightly less than reducing the number of urban cuts.

Domestic consumers are not prepared to pay more for improvements to the multiple interruption standard. Currently compensation is paid after four or more cuts. Changing this to three or more has no value for domestic consumers, but they do expect a large discount if the standard is relaxed so that payments are made after 5 or more unplanned cuts; a discount of £21, or 5.7% of the bill, would be required in this case. Domestic consumers also see no value in a change so that compensation would be automatic only for the 18 hour standard, but automatic compensation for all standards does have some value (£5, 1.5% of total bill).

Businesses, in contrast, see some value in tightening the standard so that payments are made after three cuts or more (1.2%), but do not expect a discount if the standard is relaxed with payments made after 5 or more cuts. Of a number of different levels of compensation improvements tested, only the highest level, comprising automatic compensation on a 14 hour standard with amounts linked to bill size, was valued at all, and even then only marginally by small companies (less than 1% of the their total bill). In general, business consumers comment that compensation amounts are not adequate to make up for the business losses caused by power cuts.

Both rural and urban residents are prepared to pay towards undergrounding of the network in national parks and areas of outstanding natural beauty. For each percentage of the network undergrounded per year, consumers are prepared to pay about £2.50 per year, or 0.7% of the bill.

APPENDIX A

Business and Domestic Recruitment Questionnaires

Accent
Marketing & Research

1204 Final Main Phase 2 Business Recruitment Questionnaire

Recruiter name: | Recruiter number: | Date: | Recruited:

Interviewer name: | Interviewer number: | Date: | Questionnaire Int'vd number:

URN number:

Time started: | Time completed: | Interview number | Computer number

Respondent Details

Respondent name: .....

Job title: .....

Company name: .....

Address: .....

.....

Tel No. .....

DNO & Show Material Sent

DNO: | Set 1: | Set 2

Appointment 1: Date & Time

Date of interview: ..... Time of interview: .....

Appointment 2: Date & Time

Date of interview: ..... Time of interview: .....

Appointment 3: Date & Time

Date of interview: ..... Time of interview: .....

Appointment 4: Date & Time

Date of interview: ..... Time of interview: .....

Introduction

Good morning/afternoon/evening. My name is …… and I am calling from Accent Marketing & Research. We are an independent market research company carrying out research on behalf of Ofgem, the gas and electricity industry regulator. Please could I speak to the person responsible paying the company's electricity bill? (**PROMPT IF NECESSARY**: this could be the company's Energy Manager, Facility Manager, Finance Director or Owner/Manager)

WHEN SPEAKING TO APPROPRIATE CONTACT, CONTINUE WITH EXPLANATION

Good morning/afternoon/evening. My name is …… and I am calling from Accent Marketing & Research. We are an independent market research company and I am carrying out research on behalf of Ofgem, the gas and electricity industry regulator. The research is looking at what improvements business and domestic customers would most like to see to the service supplied by electricity distribution companies. This is a bona fide market research exercise, which is being conducted under the Market Research Society Code of Conduct. As we are looking for a range of different people to take part in our research could you please spare 2 or 3 minutes to run through a couple of questions to see if you are in scope for the study?

Screening Questions

Q1. PLEASE ENTER WHETHER YOU HAVE BEEN REFERRED TO A HEAD OFFICE SITE OR WHETHER YOU ARE INTERVIEWING SOMEONE AT THE SITE ON THE SAMPLE

1. head office
2. sample site

Q1B **IF Q1 = 1 (IE HEAD OFFICE)** write town where site is located here (ie town on sample), **ELSE GO TO Q2.**

Town:.....

Q2. **ASK:** Could you please tell me the first half of: **READ OUT EITHER**

IF Q1=2 (SAMPLE SITE) "your postcode"

OR

IF Q1=1 (HEAD OFFICE REFERRAL) "the postcode of your **(READ OUT THE TOWN WHERE SITE ON SAMPLE IS LOCATED)** site"?

ENTER 1ST HALF; IE, IF SW14 2PG ENTER SW14; IF W1 5RT ENTER W1

Q3. Have you experienced any power cuts at: **READ OUT EITHER**

IF Q1 = 2 (SAMPLE SITE) "the company"
OR
IF Q1 = 1 (HEAD OFFICE REFERRAL) "that site"

…lasting more than 3 minutes in the last 12 months that you were not warned about?

1. yes
2. no
3. can't remember

CHECK QUOTAS AND PROCEED IF POSSIBLE

Q4. Is the maximum electricity demand for: **READ OUT EITHER**

IF Q1 = 2 (SAMPLE SITE) "your organisation"
OR
IF Q1 = 1 (HEAD OFFICE REFERRAL) "that site"

READ OUT RESPONSE CODES

1	1MW+	3	<100KW
2	100KW - <1MW	4	**DO NOT READ** don't know

CHECK QUOTAS AND PROCEED IF POSSIBLE

Q5. What is the approximate cost of:

IF Q1 = 2 (SAMPLE SITE) "your annual electricity bill"
OR
IF Q1 = 1 (HEAD OFFICE REFERRAL) "that site's annual electricity bill"

RECORD ACTUAL COST & BANDED COST

a) £ .....
b)

1	More than £159,000	3	<£15,000
2	£15,000-£159,000	4.	don't know

CHECK QUOTAS AND PROCEED IF POSSIBLE

Main Invitation

As I mentioned, we are carrying out a research study for Ofgem, the gas and electricity industry regulator. It is a very important study, the aim of which is to determine what improvements customers such as yourself would most like to see to the service supplied by electricity distribution companies. You are in scope for this research and we would greatly appreciate it if you were able to spare the time to give your views in a 30-minute interview which would be conducted by telephone at a time to suit you in the next few days. None of your comments will be attributed to you or your company personally and will only be used in grouped format. Would you be willing to take part?

IF Q5A IS BLANK (IE THEY WERE UNABLE TO PROVIDE ACTUAL – OR A GOOD ESTIMATE – OF COST) PLEASE CHECK THAT THEY WOULD BE ABLE TO FOR THE INTERVIEW ITSELF; IF NOT, THANK & CLOSE

IF RESPONDENT AGREES TO AN INTERVIEW, ASK THEM FOR THEIR PREFERRED DATE & TIME AND RECORD DETAILS ON FRONT SHEET. PLEASE INFORM THEM THAT YOU NEED TO SEND THEM SOME MATERIAL TO REFER TO AND ASK IF THEY WOULD PREFER TO HAVE IT FAXED, EMAILED OR POSTED. RECORD PREFERRED DETAILS BELOW.

FAX NO.....

EMAIL ADDRESS: .....

COMPANY NAME: .....

ADDRESS:.....

.....

I confirm that this interview was conducted under the terms of the MRS code of conduct and is completely confidential
Interviewer's signature: .....

Accent
Marketing & Research

1204
Final Main Phase 2 Consumer Recruitment Questionnaire

Interviewer name: | Interviewer | Date number | Questionnaire Int'vd number:

Time started: | Time completed: | Respondent number | Computer number

Respondent Details

Respondent name: .....

Address: .....

.....

Tel No. .....

Introduction

Good morning/afternoon/evening. My name is …… and I work for Accent Marketing & Research. We are an independent market research company carrying out research on behalf of Ofgem, the gas and electricity industry regulator. Please could I speak to the person responsible – either jointly or solely – for paying the electricity bill?

WHEN SPEAKING TO APPROPRIATE CONTACT, CONTINUE

(Good morning/afternoon/evening. My name is …… and I work for Accent Marketing & Research. We are an independent market research company and I am carrying out research on behalf of Ofgem, the gas and electricity industry regulator.) The research is looking at what improvements domestic and business customers would most like to see to the service supplied by electricity distribution companies. This is a bona fide market research exercise, which is being conducted under the Market Research Society Code of Conduct. As we are looking for a range of different people to take part in our research could you please spare 2 or 3 minutes to run through a couple of questions to see if you are in scope for the study?

Screening Questions

Q6. DO NOT ASK; RECORD WHETHER INTERVIEWING IN A RURAL OR URBAN AREA.

1. rural
2. urban

Q7. Do you or any members of your family work in market research, journalism, PR or the electricity industry?

1. yes **THANK AND CLOSE**
2. no

Q8. **ASK:** Could you please tell me the first half of your postcode? **IF POSTCODE IS SW14 2PG ENTER SW14; IF POSTCODE IS W1 5RT ENTER W1.**.

Q9. Have you experienced any power cuts lasting more than 3 minutes over the last 5 years that you were not warned about?

1. yes
2. no
3. can't remember **CODE AS "NO" FOR QUOTAS**

CHECK QUOTAS AND PROCEED IF POSSIBLE

Q10. Into which of the following age bands do you fall?

1. 16-19 } 1
2. 20-29 }
3. 30-39 } 2
4. 40-49 }
5. 50-59 } 3
6. 60+ }
7. refused/not stated

CHECK QUOTAS AND PROCEED IF POSSIBLE

Q11. What is the occupation of the chief wage earner in your household?

.....

CODE SEG ACCORDINGLY

1. AB
2. C1C2
3. DE

CHECK QUOTAS AND PROCEED IF POSSIBLE

Q12. How much do you pay annually for your electricty?

£ .....

Main Invitation

As I mentioned, we are carrying out a research study for Ofgem, the gas and electricity industry regulator. It is a very important study designed to determine what improvements customers such as yourself would most like to see to the service supplied by electricity distribution companies. You are in scope for this research and we would greatly appreciate it if you were able to spare the time to give your views in a 30-minute interview which could either be conducted now, or at a time to suit you. None of your comments will be attributed to you personally and will only be used in grouped format. Would you be willing to take part?

IF Q7 IS BLANK (IE THEY WERE UNABLE TO PROVIDE ACTUAL – OR A GOOD ESTIMATE – OF COST) PLEASE CHECK THAT THEY WOULD BE ABLE TO FOR THE INTERVIEW ITSELF; IF NOT, THANK & CLOSE

IF RESPONDENT AGREES TO AN IMMEDIATE INTERVIEW PROCEED TO MAIN COMPUTER INTERVIEW

IF RESPONDENT AGREES TO AN INTERVIEW AT A LATER DATE, ASK THEM FOR THEIR PREFERRED DATE & TIME AND RECORD BELOW.

.....**DATE:** .....

.....**TIME:** .....

I confirm that this interview was conducted under the terms of the MRS code of conduct and is completely confidential

Interviewer's signature: .....

APPENDIX B

Domestic Questionnaires

Phase 2 Main Consumer

INTERVIEWER DETAILS

Q 1 STATUS

INTERVIEWER: IS THIS A REAL OR PRACTICE INTERVIEW?

real interview
practice interview

Q 3 INTNO

INTERVIEWER: PLEASE ENTER YOUR FOUR DIGIT INTERVIEWER NUMBER

L 1000
H 9999

Q 3 QNO

INTERVIEWER: PLEASE ENTER THE RECRUITMENT QUESTIONNAIRE NUMBER

L 1
H 9999

Q 1 DNO

INTERVIEWER: PLEASE ENTER THE DNO AREA THAT YOU ARE SURVEYING IN

Aquila
EPN (EDF)
EME
Manweb (SP)
NEDL
Scottish Hydro Electric
Scottish Power
Southern Electric
SPN (EDF)
United Utilities
WPD South-Wales
WPD South-West
YEDL

Q 1 DNOCHECK

INTERVIEWER: YOU ARE INTERVIEWING A RESPONDENT FROM THE #DNO# AREA

IS THIS CORRECT?
yes
no

IF #DNOCHECK# EQ 1 GO TO RURALURBAN
IF #DNOCHECK# EQ 2 GO TO DNO

Q 1 RURALURBAN

INTERVIEWER: PLEASE ENTER WHETHER YOU ARE SURVEYING IN A RURAL OR URBAN AREA

rural
urban

MAIN INTERVIEW: Background

Q 0 INTRO

Thank you for agreeing to take part in this survey. As I have said, any answer you give will be treated in confidence in accordance with the Code of Conduct of the Market Research Society.

You do not have to answer questions you do not wish to and you can terminate the interview at any point.

Q 2 POSTCODE
Can I begin by asking you for the first half of your postcode, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg: IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12; IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1

Q 0 INTRO2
This interview is about electricity distribution rather than supply. In other words, it is about the company that runs the local network of wires or cables that transmit electricity, rather than the company that you pay the bills to. Because they are the ones who are responsible for the wires, they are also responsible for:

* restoring the power supply if there is a power cut
* operating a safety & security enquiry service for any problems with live cables
* connecting customers to their local network
* and investigating any complaints or problems that customers have regarding their electricity distribution service.

Q 5 ELECBILL
Can you please tell me what you pay each year for your electricity?

INTERVIEWER: IT IS ESSENTIAL TO GET THIS INFORMATION. IF THE RESPONDENT KNOWS A MONTHLY AMOUNT MULTIPLY THIS BY 12; IF THEY KNOW A QUARTERLY AMOUNT MULTIPLY THIS BY 4 (BUT TRY TO GET A DISTINCTION BETWEEN WINTER AND SUMMER MONTHS AND CALCULATE ACCORDINGLY).

L 1
H 999999

Q 1 BILLCHECK
Your electricity bill for the year is roughly, or exactly, #ELECBILL#. Is this correct?

yes
no

IF #BILLCHECK# EQ 1 GO TO BILLCALC
IF #BILLCHECK# EQ 2 GO TO ELECBILL

Q 5 BILLCALC
V 5 BILLCAL
M BILLCAL [= #ELECBILL# P 24]

Q 0 DISTBILL
About 24% of your current electricity bill currently goes towards electricity distribution, which means that, for you, about #BILLCALC# of your annual bill goes towards distribution.

S EXPERIENCES

Q 0 INTRO3
The remainder of this questionnaire is split into a number of sections. In the first section I would like to look at your experiences with respect to electricity distribution issues.

Firstly, can you tell me if you have experienced any of the following in the past 12 months:

Q 1 Q1
Any unplanned power cuts lasting more than 3 minutes, ie any that you were not warned about?

yes
no
don't know/can't remember

Q 3 Q2

IF #Q1# NE 1 GO TO Q4
How many of these unplanned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q3
On the last occasion that you had an unplanned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q4
And have you experienced any planned power cuts (ie ones that you were given advance warning of) lasting more than 3 minutes in the past 12 months?

yes
no
don't know/can't remember

Q 3 Q5
IF #Q4# NE 1 GO TO Q7
How many of these planned cuts have you had in the past twelve months?

T INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q6
On the last occasion that you had a planned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q7
IF #Q1# NE 1 GO TO Q13
On the last occasion that you experienced an unplanned power cut, did you try and contact your electricity distributor?

yes
no
don't know

Q 1 Q8
IF #Q7# NE 1 GO TO Q13
Did you manage to get through?

yes
no
don't know/can't remember

Q 3 Q9
IF #Q8# NE 1 GO TO Q13
How long did you take to get through initially, whether to an automated message or a person?
DO NOT PROMPT

INTERVIEWER: RECORD IN SECONDS; RECORD 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q10
Did you get an:

1. Automated message
2. Speak to someone
3. Both

Automated message
Spoke to someone
Both
don't know/can't remember

Q 1 Q11
Did you get the information you wanted?

yes
no
don't know/can't remember

Q 1 Q12
IF #Q11# NE 1 GO TO Q13
Was the information about the power cut correct?

yes
no
don't know/can't remember

EXPECTATIONS ABOUT POWER SUPPLY

Q 1 Q13
Do you believe that it is reasonable for a power cut to occur in a major storm?

yes
no
don't know/not stated

Q 3 Q14
And what is the maximum number of an unplanned power cuts lasting more than three 5hours that a company should be allowed in any one year before compensation is paid to their customers?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 1 Q15
In normal conditions, how quickly would you expect power to be restored following an unplanned power cut?

DO NOT PROMPT

1. within 1 hour
2. within 2-3 hours
3. within 4-5 hours
4. within 6-10 hours
5. within 11-15 hours
6. within 16-18 hours
7. 18 hours or more

within 1 hour
2-3 hours

4-5 hours
6-10 hours
11-15 hours
16-18 hours
18 hours or more
don't know

Q 3 Q16
And in normal conditions, after how long (ie after how many hours of a power cut) should a distributor be required to pay compensation to a consumer?

INTERVIEWER: IF RESPONDENT SAYS "IMMEDIATELY" PLEASE ENTER "0

L 0
H 999

Q 3 Q17
If there had been a major storm affecting 1% of customers in your distribution company's area, how quickly would you expect power to be restored in such a case, to the nearest hour?

DO NOT PROMPT

ENTER RESPONSE IN HOURS OR 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q18
Do you think that distribution companies should be doing more to reduce the impact of severe weather on their networks?

yes
no
don't know

ATTITUDES TOWARDS STANDARDS & TARGETS

Q 0 INTRO4
Ofgem, the regulator for the gas and electricity market, has put in place a number of standards which distributors are required to meet. If they fail to meet them then customers are entitled to compensation. I am going to run through some of the standards and ask a question about each?

Q 1 Q19
Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £50 for domestic customers for the first 18 hrs plus £25 for each additional 12 hours.

Were you aware of this standard?

yes
no
can't remember

Q 1 Q20
Consumers are entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year

Were you aware of this Standard?

yes
no
can't remember

Q 1 Q21
Consumers must be given at least 2 days notice of a planned power cut. Failure to do so results in a penalty payment of £20 for domestic consumers.

Were you aware of this standard?

yes
no
can't remember

STATED PREFERENCE

Q 0 SPINTRO1A
I am now going to go through four exercises with you, each of which will look at your preferences for a number of changes that distribution companies could make to the service that they provide.

The first will look at:

the number of power cuts greater than 3 minutes experienced in rural areas over 5 years
the number of power cuts greater than 3 minutes experienced in urban areas over 5 years
and the average length of these power cuts.

Q 0 SPINTRO1B
You will be presented with six sets of choice pairs and will be asked in each case to say whether you prefer Option A or B. You may not like either, but please say which you would prefer in each instance.

* variable 1 DESIGN (Number of power cuts (3 mins) in rural areas over 5 years

More power cuts in rural areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA+1/2/3) over 5 years

The same number of power cuts in rural areas:- ie an average of (DNO SPECIFIC DATA) in 5 years

Fewer power cuts in rural areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA –1/2/3)over 5 years

* variable 2 design (Number of power cuts (3 mins) in urban areas over 5 years

More power cuts in urban areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +1)over 5 years

The same number of power cuts in urban areas:- ie an average (DNO SPECIFIC DATA) cuts in 5 years

Fewer power cuts in urban areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA -1)over 5 years

* variable 3 design (Average length of power cuts (3 mins) experienced by customers:)

Longer average power cut duration:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +5/10/15/20) minutes

No change in average power cut duration:- ie an average of (DNO SPECIFIC DATA) minutes

Shorter average power cut duration:- ie from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA –5/10/15/20) minutes

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO2A

In this second exercise we are going to look at:

the ability of the distribution networks to withstand major storms and their ability to restore customers' power quickly following major damage to their network

provision of information during a power cut

and undergrounding overhead lines to reduce the visual impact of these overhead lines

You will see that for the first of these we talk about your local company's electricity system being designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is reduced. Please note that 1% of your distributors customers is (DNO SPECIFIC DATA).

Please also note that when we refer to overhead lines we are talking about these (show SHOWCARD A)

Q 0 SPINTRO2B
With this in mind, which of the following would you prefer?

G B 1 GAME2
* variable 1 DESIGN (electricity system)
Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is once a year, as now

Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is once **every 2 years**, better than now

Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is once **every 5 years**, better than now

* variable 2 design (Provision of information)

Current level of information:
- (DNO SPECIFIC DATA) of callers receive information by automated message
(DNO SPECIFIC DATA) of callers are answered by a person on average in (DNO SPECIFIC DATA) seconds (this including some customers who have already heard an automated message)

Current level of information provision during a power cut, **but with information given by the automated message or operator being updated every 2 hours to ensure that is accurate**

Current level of information provision during a power cut, **but with call backs to you by a person to provide information updates, if requested**

Current level of information provision during a power cut, **plus a dedicated helpline for customers dependent on medical equipment requiring an electricity supply**

* variable 3 design (Undergrounding for environmental visual amenity reasons:)

No additional overhead lines to be undergrounded to reduce the visual impact of these overhead lines

An ongoing commitment to undergrounding **#G2V3L2A#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

An ongoing commitment to undergrounding **#G2V3L2B#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

An ongoing commitment to undergrounding **#G2V3L2C#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

*Percentage undergrounded range from 2.5% to 7.5%

Which choice would you prefer?
CHOICE A

CHOICE B

Q 0 SPINTRO3A
We are now going to look at:

the maximum time taken to restore customers following storms

the number of UNPLANNED interruptions greater than 3 hours which would entitle you to a compensation payment

automatic compensation arrangements

Q 0 SPINTRO3B
When considering these options please be aware that, with respect to UNPLANNED interruptions greater than 3 hours, consumers are currently entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year.

And with respect to the compensation arrangements, currently consumers have to claim compensation under all Ofgem interruption standards, it is not given automatically.

Q 0 SPINTRO3C
With this in mind, which of the following would you prefer?

G B 1 GAME3
* variable 1 DESIGN (Maximum time taken to restore customers following storms)

The maximum time taken to restore customers following storms would be within 60 hours, worse than now

The maximum time taken to restore customers following storms would be within 48 hours as now

The maximum time taken to restore customers following storms would be within 36 hours, better than now

The maximum time taken to restore customers following storms would be within 24 hours, better than now

* variable 2 design (Number of UNPLANNED interruptions greater than 3 hours which entitles you to a compensation payment is:)

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be worse than now at 5 or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be as now, ie or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be better than now at 3 or more interruptions

* variable 3 design (Automatic compensation)

Current compensation arrangements would apply, ie customers have to claim compensation under ALL the interruption standards after the supply has been restored

There is automatic compensation for the 18 hour interruption standard but **not** for the planned interruption and multiple interruption standards

There is automatic compensation for ALL interruption standards

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO4A
In this final exercise you will see both the best and worse options of all areas that we have just looked at in the first three exercises.

In addition, because no improvements would be possible without investment by the distribution companies – and consequently an increase in your electricity bill - you will also see the impact that the improvements shown would have on your overall electricity bill in year one and in subsequent years.

Bearing this in mind, and referring to the showcard for the full definitions of each level shown on the screen, we would once again like you to say which of the options you would prefer, A or B.

INTERVIEWER: IT IS ESSENTIAL THAT YOU SHOW THE RESPONDENT THE RELEVANT FULL LEVELS ON SHOWCARD B AS WELL AS SHOWING THEM THE SCREEN

G B 1 GAME4A
* variable 1 DESIGN (EXERCISE 1 LEVELS)
* level 1 best Ex 1 package
Fewer rural cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Fewer urban cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Shorter average cut duration: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA) minutes

* level 2 worst Ex 1 package
More rural cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

More urban cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Longer average cut duraion: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA) minutes

* variable 2 design (EX 2 LEVELS)
* BEST PACKAGE GAME2
• Likelihood of 1% customers losing power for 24 hours following a major storm is once every 5 years, better than now
• Current information provision on cut, plus a dedicated helpline for customers dependent on electricity for medical reasons
• Ongoing commitment to undergrounding #G2V3L2C# of overhead lines pa in national parks and areas of natural beauty

* WORST PACKAGE 2
• Likelihood of 1% customers losing power for 24 hours following a major storm is once a year, as now
• Current level of information provision during a cut
• No additional overhead lines to be undergrounded to reduce visual impact

* variable 3 design (EX 3 LEVELS)
* BEST EX 3 PACKAGE
• Maximum restoration time following a storm better than now: within 24 hours
• Number of **unplanned** interruptions 3 hours entitling you to compensation: better than now at 3 or more
• Automatic compensation for ALL interruption standards

* WORST EX 3 PACKAGE
• Maximum restoration time following a storm worse than now: within 60 hours
• Number of **unplanned** interruptions 3 hours entitling you to compensation worse than now at 5 or more
• Current compensation arrangements ie customers have to claim

G O 3 2
* VARIABLE 4 - COST
* LEVEL 1 - 1%-4% decreases
* LEVEL 2 - current
* LEVEL 3 - 1%-4% increases
* LEVEL 4 - 5%-8% increases

Your annual electricity bill would decrease from **CURRENT BILL** to **CURRENT BILL – LEVEL 1**

Your annual electricity bill would stay the same **CURRENT BILL**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 3**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 4**

Which choice would you prefer?
CHOICE A
CHOICE B

RELATIVE PRIORITIES

Q 1 Q22
Thank you for going through those exercises with me.

Could you now tell me how you would feel if you were to get an additional power cut over the next 12 months that you were not warned about? Please use a scale of 1 to 4, where 1 is equal to extremely unhappy, 2 to very unhappy, 3 to quite unhappy and 4 to indifferent.

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 10 Q23
And using the same scale, how would you feel if you were to get an additional power cut over the next 12 months that you were warned about?

Q 1 Q24
And how would you feel if the length of the power cut was to increase from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +20)MINS?

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 1 Q25
If you were to call your distribution company in the event of a power cut and were to receive an automated message providing information about the cut and measures being taken to address it, would you then prefer to hold for an operator to report the cut or receive further information, or would you prefer to be able to call back on a dedicated priority number. Calls to the dedicated number would be likely to be answered more quickly because of the smaller volume of calls to that number.

prefer to hold
prefer to call back
neither, auto message enough
Don't know

DEMOGRAPHICS & CONTEXTUAL QUESTIONS

Q 1 Q26
Finally I would like to ask you a couple of questions to help with the analysis of this survey. First, do you have any health problems, a disability or a long term illness that restricts your daily activities or the work that you do?

yes
No
Refused

Q 3 Q27
How many, if any, children do you have in your household under the age of 5?
L 0
H 50

Q 1 Q28
And which of the following best describes your total annual household income, before tax and other deductions?

under £10,000
£10,000 - £20,000
£20,001 - £30,000
£30,001 - £40,000
£40,001 - £50,000
£50,001 - £60,000
over £60,000
Don't know
Refused

Q 1 Q29
Which of the following age bands do you fall into?

NOTE: THIS CAN BE RECORDED FROM THE RECRUITMENT QUESTIONNAIRE IF YOU HAVE IT TO HAND.

16-19
20-29
30-39
40-49
50-59
60+
Refused/ns

Q 1 Q30
And what is the occupation of the chief wage earner in your household?

NOTE: THIS CAN BE RECORDED FROM THE RECRUITMENT QUESTIONNAIRE IF YOU HAVE IT TO HAND.

IF NOT, ENTER RESPONSE IN NOTEPAD AND CODE SEG BELOW ACCORDINGLY

AB (occ. in NOTE)
C1C2 (occ. in NOTE)
DE (occ. in NOTE)
Don't know (occ. in NOTE)
Refused

Q 1 Q31
INTERVIEWER: CODE GENDER OF RESPONDENT.(DO NOT ASK)

Male
Female

END OF INTERVIEW

Q 0 ThankU
THAT WAS THE LAST QUESTION.

Please can I take a note of your name and telephone number for quality control purposes

---

Q 2 NAME
Respondent name:

Q 2 WkTel
Home Telephone:

Q 0 END
That was the last question. Thank you very much for taking part in this research.

INTERVIEWER: HAND RESPONDENT THANK YOU LETTER AND INCENTIVE.

Q 1 STATUS2

INTERVIEWER: PLEASE RE-ENTER WHETHER REAL OR PRACTICE INTERVIEW

real interview
practice interview

Q 1 MRSCODE
INTERVIEWER: DO YOU CONFIRM THAT THIS INTERVIEW WAS CONDUCTED UNDER THE TERMS OF THE MARKET RESEARCH SOCIETY CODE OF CONDUCT AND IS COMPLETELY CONFIDENTIAL

Yes
No

Phase 2 MAIN Consumer - LPN only

INTERVIEWER DETAILS

Q 1 STATUS

INTERVIEWER: IS THIS A REAL OR PRACTICE INTERVIEW?

real interview
practice interview

Q 3 INTNO

INTERVIEWER: PLEASE ENTER YOUR FOUR DIGIT INTERVIEWER NUMBER

L 1000
H 9999

Q 3 QNO

INTERVIEWER: PLEASE ENTER THE RECRUITMENT QUESTIONNAIRE NUMBER

L 1
H 9999

Q 1 DNO

INTERVIEWER: PLEASE ENTER THE DNO AREA THAT YOU ARE SURVEYING IN

LPN (EDF)

MAIN INTERVIEW: Background

Q 0 INTRO
Thank you for agreeing to take part in this survey. As I have said, any answer you give will be treated in confidence in accordance with the Code of Conduct of the Market Research Society.

You do not have to answer questions you do not wish to and you can terminate the interview at any point.

Q 2 POSTCODE
Can I begin by asking you for the first half of your postcode, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg:
IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12
IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1

Q 0 INTRO2
This interview is about electricity distribution rather than supply. In other words, it is about the company that runs the local network of wires or cables that transmit electricity, rather than the company that you pay the bills to. Because they are the ones who are responsible for the wires, they are also responsible for:

* restoring the power supply if there is a power cut
* operating a safety & security enquiry service for any problems with live cables
* connecting customers to their local network
* and investigating any complaints or problems that customers have regarding their electricity distribution service.

Q 5 ELECBILL
Can you please tell me what you pay each year for your electricity?

INTERVIEWER: IT IS ESSENTIAL TO GET THIS INFORMATION. IF THE RESPONDENT KNOWS A MONTHLY AMOUNT
MULTIPLY THIS BY 12; IF THEY KNOW A QUARTERLY AMOUNT MULTIPLY THIS BY 4 (BUT TRY TO GET A DISTINCTION BETWEEN WINTER AND SUMMER MONTHS AND CALCULATE ACCORDINGLY).

L 1
H 999999

Q 1 BILLCHECK

Your electricity bill for the year is roughly, or exactly, #ELECBILL#. Is this correct?

Yes
No

IF #BILLCHECK# EQ 1 GO TO BILLCALC
IF #BILLCHECK# EQ 2 GO TO ELECBILL

Q 5 BILLCALC
V 5 BILLCAL
M BILLCAL [= #ELECBILL# P 24]
F 1 #BILLCAL#

Q 0 DISTBILL
About 24% of your current electricity bill currently goes towards electricity distribution, which means that, for you, about #BILLCALC# of your annual bill goes towards distribution.

EXPERIENCES

Q 0 INTRO3
The remainder of this questionnaire is split into a number of sections. In the first section I would like to look at your experiences with respect to electricity distribution issues.

Firstly, can you tell me if you have experienced any of the following in the past 12 months:

Q 1 Q1
Any unplanned power cuts lasting more than 3 minutes, ie any that you were not warned about?

Yes
No
Don't know/can't remember

Q 3 Q2
IF #Q1# NE 1 GO TO Q4
How many of these unplanned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q3
On the last occasion that you had an ^C15unplanned^C07 power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW

L 1
H 9999

Q 1 Q4
And have you experienced any planned power cuts (ie ones that you were given advance warning of) lasting more than 3 minutes in the past 12 months?

Yes
No
Don't know/can't remember

Q 3 Q5

IF #Q4# NE 1 GO TO Q7
How many of these planned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q6
On the last occasion that you had a planned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW

L 1
H 9999

Q 1 Q7
IF #Q1# NE 1 GO TO Q13
On the last occasion that you experienced an unplanned power cut, did you try and contact your electricity distributor?

Yes
No
Don't know

Q 1 Q8
IF #Q7# NE 1 GO TO Q13
Did you manage to get through?

Yes
No
Don't know/can't remember

Q 3 Q9
IF #Q8# NE 1 GO TO Q13
How long did you take to get through initially, whether to an automated message or a person?

DO NOT PROMPT

INTERVIEWER: RECORD IN SECONDS; RECORD 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q10
Did you get an:

1. Automated message
2. Speak to someone
3. Both

Automated message
Spoke to someone
Both
Don't know/can't remember

Q 1 Q11
Did you get the information you wanted?

Yes
No
Don't know/can't remember

Q 1 Q12

IF #Q11# NE 1 GO TO Q13
Was the information about the power cut correct?

Yes
No
Don't know/can't remember

EXPECTATIONS ABOUT POWER SUPPLY

Q 1 Q13
Do you believe that it is reasonable for a power cut to occur in a major storm?
Yes
No
Don't know/not stated

Q 3 Q14
And what is the maximum number of unplanned power cuts lasting more than three hours that a company should be allowed in any one year before compensation is paid to their customers?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 1 Q15
In normal conditions, how quickly would you expect power to be restored following an unplanned power cut?

DO NOT PROMPT

1. within 1 hour
2. within 2-3 hours
3. within 4-5 hours
4. within 6-10 hours
5. within 11-15 hours
6. within 16-18 hours
7. 18 hours or more

within 1 hour
2-3 hours
4-5 hours
6-10 hours
11-15 hours
16-18 hours
18 hours or more
Don't know

Q 3 Q16
And in normal conditions, after how long (ie after how many hours of a power cut) should a distributor be required to pay compensation to a consumer?

INTERVIEWER: IF RESPONDENT SAYS "IMMEDIATELY" PLEASE ENTER "0

L 0
H 999

Q 3 Q17
If there had been a major storm affecting 1% of customers in your distribution company's area, how quickly would you expect power to be restored in such a case, to the nearest hour?

DO NOT PROMPT

ENTER RESPONSE IN HOURS OR 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q18
Do you think that distribution companies should be doing more to reduce the impact of severe weather on their networks?

Yes
No
Don't know

ATTITUDES TOWARDS STANDARDS & TARGETS

Q 0 INTRO4
Ofgem, the regulator for the gas and electricity market, has put in place a number of standards which distributors are required to meet. If they fail to meet them then customers are entitled to compensation. I am going to run through some of the standards and ask a question about each?

Q 1 Q19
Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £50 for domestic customers for the first 18 hrs plus £25 for each additional 12 hours.

Were you aware of this standard?

Yes
No
A can't remember

Q 1 Q20
Consumers are entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year

Were you aware of this Standard?

Yes
No
A can't remember

Q 1 Q21
Consumers must be given at least 2 days notice of a planned power cut. Failure to do so results in a penalty payment of £20 for domestic consumers.

Were you aware of this standard?

Yes
No
can't remember

STATED PREFERENCE

Q 0 SPINTRO1A
I am now going to go through three exercises with you, each of which will look at your preferences for a number of improvements that distribution companies could make to the service that they provide.

The first will look at:

- the number of power cuts greater than 3 minutes experienced in urban areas over 5 years
- the average length of these power cuts and
- the provision of information during a power cut.

Q 0 SPINTRO1B

You will be presented with six sets of choice pairs and will be asked in each case to say whether you prefer Option A or B. You may not like either, but please say which you would prefer in each instance.

GAME1
* variable 1 DESIGN (Number of power cuts (3 mins) in urban areas over 5 years:)
More power cuts in urban areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +1)over 5 years

The same number of power cuts in urban areas:- ie an average (DNO SPECIFIC DATA) cuts in 5 years

Fewer power cuts in urban areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA -1)over 5 years

* variable 2 design (Average length of power cuts (3 mins) experienced by customers:)

Longer average power cut duration:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +5/10/15/20) minutes

No change in average power cut duration:- ie an average of (DNO SPECIFIC DATA) minutes

Shorter average power cut duration:- ie from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA – 5/10/15/20) minutes

* variable 3 design (Provision of information)

Current level of information: **28%** of callers receive information by automated message

45% of callers are answered by a person on average in **62** seconds (this including some customers who have already heard an automated message)

Current level of information provision during a power cut, **but with information given by the automated message or operator being updated every 2 hours to ensure that it is accurate**

Current level of information provision during a power cut, **but with call backs to you by a person to provide information updates, if requested**

Current level of information provision during a power cut, **plus a dedicated helpline for customers dependent on medical equipment requiring an electricity supply**

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO2A

We are now going to look at:

the number of UNPLANNED interruptions greater than 3 hours which would entitle you to a compensation payment automatic compensation arrangements and undergrounding overhead lines to reduce the visual impact of these overhead lines.

Q 0 SPINTRO2C
When considering these options please be aware that, with respect to UNPLANNED interruptions greater than 3 hours, consumers are currently entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year.

And with respect to the compensation arrangements, currently consumers have to claim compensation under all Ofgem interruption standards, it is not given automatically.

Please also note that when we refer to overhead lines we are talking about these (show SHOWCARD A)

Q 0 SPINTRO2D

With this in mind, which of the following would you prefer?

* variable 1 design (Number of UNPLANNED interruptions greater than 3 hours which entitles you to a compensation payment is:)

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be worse than now at 5 or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be as now, ie 4 or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be better than now at 3 or more interruptions

* variable 2 design (Automatic compensation)
Current compensation arrangements would apply, ie customers have to claim compensation under ALL the interruption standards after the supply has been restored

There is automatic compensation for the 18 hour interruption standard but **not** for the planned interruption and multiple interruption standards

There is automatic compensation for ALL interruption standards

* variable 3 design (Undergrounding for environmental visual amenity reasons:)

No additional overhead lines to be undergrounded to reduce the visual impact of these overhead lines

An ongoing commitment to undergrounding **#G2V3L2A#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

An ongoing commitment to undergrounding **#G2V3L2B#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

An ongoing commitment to undergrounding **#G2V3L2C#** of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

*Percentage undergrounded range from 2.5% to 7.5%

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO3A
In this final exercise you will see both the best and worse options of all areas that we have just looked at in the first two exercises.

In addition, because no improvements would be possible without investment by the distribution companies – and consequently an increase in your electricity bill - you will also see the impact that the improvements shown would have on your overall electricity bill in year one and in subsequent years.

Bearing this in mind, and referring to the showcard for the full definitions of each level shown on the screen, we would once again like you to say which of the options you would prefer, A or B.

INTERVIEWER: **IT IS ESSENTIAL** THAT YOU SHOW THE RESPONDENT THE RELEVANT FULL LEVELS ON SHOWCARD B AS WELL AS SHOWING THEM THE SCREEN

G B 1 GAME3A
* variable 1 DESIGN (EXERCISE 1 LEVELS)
* level 1 best Ex 1 package

Fewer urban cuts over 5 years: from 2 to 1

Shorter average cut duration: from 112 to #G1V2XA2# minutes

Current information provision on cut, plus a dedicated helpline for customers dependent on electricity for medical reasons

* level 2 worst Ex 1 package

More urban cuts over 5 years: from 2 to 3

Longer average cut duration: from 112 to #G1V2XA3# minutes

Current level of information provision during a cut

* variable 2 design (EX 2 LEVELS)
* BEST PACKAGE GAME2

Number of **unplanned** interruptions 3 hours entitling you to compensation: better than now at 3 or more

Automatic compensation for ALL interruption standards

Ongoing commitment to undergrounding **#G2V3L2C#** of overhead lines pa in national parks and areas of natural beauty

* WORST PACKAGE 2

Number of **unplanned** interruptions 3 hours entitling you to compensation: worse than now at 5 or more

Current compensation arrangements, ie customers have to claim

No additional overhead lines to be undergrounded to reduce visual impact

* VARIABLE 4 - COST
* LEVEL 1 - 1%-4% decreases
* LEVEL 2 - current
* LEVEL 3 - 1%-4% increases
* LEVEL 4 - 5%-8% increases

Your annual electricity bill would decrease from **CURRENT BILL** to **CURRENT BILL – LEVEL 1**

Your annual electricity bill would stay the same **CURRENT BILL**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 3**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 4**

Which choice would you prefer?
CHOICE A
CHOICE B

RELATIVE PRIORITIES

Q 1 Q22
Thank you for going through those exercises with me.

Could you now tell me how you would feel if you were to get an additional power cut over the next 12 months that you were not warned about? Please use a scale of 1 to 4, where 1 is equal to extremely unhappy, 2 to very unhappy, 3 to quite unhappy and 4 to indifferent.

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 10 Q23
And using the same scale, how would you feel if you were to get an additional power cut over the next 12 months that you were warned about?

Q 1 Q24
And how would you feel if the length of the power cut was to increase from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +20) MINS?

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 1 Q25
If you were to call your distribution company in the event of a power cut and were to receive an automated message providing information about the cut and measures being taken to address it, would you then prefer to hold for an operator to report the cut or receive further information, or would you prefer to be able to call back on a dedicated priority number. Calls to the dedicated number would be likely to be answered more quickly because of the smaller volume of calls to that number.

prefer to hold
prefer to call back
neither, auto message enough
Don't know

DEMOGRAPHICS & CONTEXTUAL QUESTIONS

Q 1 Q26
Finally I would like to ask you a couple of questions to help with the analysis of this survey. First, do you have any health problems, a disability or a long term illness that restricts your daily activities or the work that you do?

Yes
No
Refused

Q 3 Q27
How many, if any, children do you have in your household under the age of 5?
L 0
H 50

Q 1 Q28
And which of the following best describes your total annual household income, before tax and other deductions?

under £10,000
£10,000 - £20,000
£20,001 - £30,000
£30,001 - £40,000
£40,001 - £50,000
£50,001 - £60,000
over £60,000
Don't know
Refused

Q 1 Q29
Which of the following age bands do you fall into?

NOTE: THIS CAN BE RECORDED FROM THE RECRUITMENT QUESTIONNAIRE IF YOU HAVE IT TO HAND.

16-19
20-29
30-39
40-49

50-59
60+
Refused/ns

Q 1 Q30
And what is the occupation of the chief wage earner in your household?

NOTE: THIS CAN BE RECORDED FROM THE RECRUITMENT QUESTIONNAIRE IF YOU HAVE IT TO HAND.

IF NOT, ENTER RESPONSE IN NOTEPAD AND CODE SEG BELOW ACCORDINGLY

AB (in NOTE)
C1C2 (in NOTE)
DE (in NOTE)
Don't know (in NOTE)
Refused

Q 1 Q31

INTERVIEWER: CODE GENDER OF RESPONDENT.(DO NOT ASK)

Male
Female

END OF INTERVIEW

Q 0 ThankU
THAT WAS THE LAST QUESTION.

Please can I take a note of your name and telephone number for quality control purposes

---

Q 2 NAME
Respondent name:

Q 2 WkTel
Home Telephone:

Q 0 END
That was the last question. Thank you very much for taking part in this research.

INTERVIEWER: HAND RESPONDENT THANK YOU LETTER AND INCENTIVE.

Q 1 STATUS2

INTERVIEWER: PLEASE RE-ENTER WHETHER REAL OR PRACTICE INTERVIEW

real interview
practice interview

Q 1 MRSCODE

INTERVIEWER: DO YOU CONFIRM THAT THIS INTERVIEW WAS CONDUCTED UNDER THE TERMS OF THE MARKET RESEARCH SOCIETY CODE OF CONDUCT AND IS COMPLETELY CONFIDENTIAL

Yes
No

APPENDIX C

Business Questionnaires

Phase 2 Main Business

INTERVIEWER DETAILS

Q 1 STATUS
INTERVIEWER: IS THIS A REAL OR PRACTICE INTERVIEW?

real interview
practice interview

Q 3 INTNO
INTERVIEWER: PLEASE ENTER YOUR FOUR DIGIT INTERVIEWER NUMBER

L 1000
H 9999

Q 1 CHECK
DOES THE RESPONDENT HAVE THE SHOW MATERIAL TO HAND; PLEASE CHECK AND DO NOT PROCEED UNTIL THEY DO OR ARRANGE TO CALL THEM BACK

proceed

Q 3 QNO
INTERVIEWER: PLEASE ENTER THE RECRUITMENT QUESTIONNAIRE NUMBER

L 1
H 9999

Q 1 SET
INTERVIEWER: PLEASE ENTER THE SET NUMBER

SET 1
SET 2
SET 3
SET 4
SET 5
SET 6

Q 2 URN
INTERVIEWER: PLEASE ENTER URN FROM SAMPLE

Q 1 SITE
INTERVIEWER: PLEASE ENTER RESPONSE TO Q1 ON THE RECRUITMENT QUESTIONNAIRE

head office
site

Q 2 SITE2
IF #SITE# EQ 2 GO TO DNO

INTERVIEWER: PLEASE TYPE IN TOWN AT WHICH THE SITE IN QUESTION IS LOCATED FROM Q1B ON THE RECRUITMENT QUESTIONNAIRE

Q 1 DNO

INTERVIEWER: PLEASE ENTER THE DNO AREA FROM WHICH SAMPLE IS DRAWN; SEE RQ

Aquila
EPN (EDF)
EME
Manweb (SP)
NEDL

Scottish Hydro Electric
Scottish Power
Southern Electric
SPN (EDF)
United Utilities
WPD South-Wales
WPD South-West
YEDL

MAIN INTERVIEW: Background

Q 0 INTRO
Thank you for agreeing to take part in this survey. As I have said, any answer you give will be treated in confidence in accordance with the Code of Conduct of the Market Research Society. You do not have to answer questions you do not wish to and you can terminate the interview at any point.

Q 2 POSTCODE1
IF #SITE# EQ 2 GO TO POSTCODE2
Can I begin by asking you for the first half of the postcode for the address of your site in #SITE2#, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg:
IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12
IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1
-

Q 2 POSTCODE2
IF #SITE# EQ 1 GO TO INTRO2
Can I begin by asking you for the first half of the postcode for your company's address, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg:
IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12
IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1

Q 0 INTRO2
This interview is about electricity distribution rather than supply. In other words, it is about the company that runs the local network of wires or cables that transmit electricity, rather than the company that you pay the bills to. As you are probably aware, distributors are responsible for:

* restoring the power supply if there is a power cut
* operating a safety & security enquiry service for any problems with live cables
* connecting customers to their local network
* and investigating any complaints or problems that customers have regarding their electricity distribution service.

Q 5 ELECBILL
Can you please tell me what you pay each year for your electricity at this #SITE2# site?

INTERVIEWER: IT IS ESSENTIAL TO GET THIS INFORMATION. IF THE RESPONDENT KNOWS A MONTHLY AMOUNT MULTIPLY THIS BY 12; IF THEY KNOW A QUARTERLY AMOUNT MULTIPLY THIS BY 4 (BUT TRY TO GET A DISTINCTION BETWEEN WINTER AND SUMMER MONTHS AND CALCULATE ACCORDINGLY).

L 1
H 999999999

Q 1 BILLCHECK
Your electricity bill for the year is roughly, or exactly, #ELECBILL#. Is this correct?

Yes
no

IF #BILLCHECK# EQ 1 GO TO BILLCALC
IF #BILLCHECK# EQ 2 GO TO ELECBILL

Q 5 BILLCALC
V 5 BILLCAL
M BILLCAL [= #ELECBILL# P 25]
F 1 #BILLCAL#

Q 0 DISTBILL
About 25% of your current electricity bill currently goes towards electricity distribution, which means that, at this #SITE2# site, about #BILLCALC# of your annual bill goes towards distribution.

EXPERIENCES

Q 0 INTRO3
The remainder of this questionnaire is split into a number of sections. In the first section I would like to look at your experiences with respect to electricity distribution issues.

Firstly, can you tell me if you have experienced any of the following in the past 12 months at this #SITE2# site:

Q 1 Q1
Any unplanned power cuts lasting more than 3 minutes, ie any that you were ^C15not^C07 warned about?
Yes
A no
Don't know/can't remember

Q 3 Q2
IF #Q1# NE 1 GO TO Q4
How many of these unplanned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q3
On the last occasion that you had an unplanned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q4
And have you experienced any planned power cuts (ie ones that you were given advance warning of) lasting more than 3 minutes in the past 12 months at this #SITE2# site?

Yes
no
Don't know/can't remember

Q 3 Q5
IF #Q4# NE 1 GO TO Q7
How many of these planned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q6
On the last occasion that you had a planned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q7
IF #Q1# NE 1 GO TO Q13
On the last occasion that you experienced an unplanned power cut, did you try and contact your electricity distributor?

Yes
no
Don't know

Q 1 Q8
IF #Q7# NE 1 GO TO Q13
Did you manage to get through?

Yes
no
Don't know/can't remember

Q 3 Q9
IF #Q8# NE 1 GO TO Q13
How long did you take to get through initially, whether to an automated message or a person?

DO NOT PROMPT

INTERVIEWER: RECORD IN SECONDS; RECORD 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q10
Did you get an:

1. Automated message
2. Speak to someone
3. Both
Automated message
Spoke to someone
Both
Don't know/can't remember

Q 1 Q11
Did you get the information you wanted?

Yes
no
Don't know/can't remember

Q 1 Q12
IF #Q11# NE 1 GO TO Q13
Was the information about the power cut correct?

Yes
no
Don't know/can't remember

EXPECTATIONS ABOUT POWER SUPPLY

Q 1 Q13
Do you believe that it is reasonable for a power cut to occur in a major storm?

Yes
no
Don't know/not stated

Q 3 Q14
And what is the maximum number of unplanned power cuts lasting more than three hours that a company should be allowed in any one year before compensation is paid to their customers?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 1 Q15
In normal conditions, how quickly would you expect power to be restored following an unplanned power cut?

DO NOT PROMPT

1. within 1 hour
2. within 1-2 hours
3. within 2-3 hours
4. within 4-5 hours
5. within 6-10 hours
6. within 11-15 hours
7. within 16-18 hours
8. 18 hours or more

within 1 hour
1-2 hours
2-3 hours
4-5 hours
6-10 hours
11-15 hours
16-18 hours
18 hours or more
Don't know

Q 3 Q16
And in normal conditions, after how long (ie after how many hours of a power cut) should a distributor be required to pay compensation to a consumer?

INTERVIEWER: IF RESPONDENT SAYS "IMMEDIATELY" PLEASE ENTER "0

L 0
H 999

Q 3 Q17
If there had been a major storm affecting 1% of customers in your distribution company's area, how quickly would you expect power to be restored in such a case, to the nearest hour?

DO NOT PROMPT

ENTER RESPONSE IN HOURS; ENTER 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q18
Do you think that distribution companies should be doing more to reduce the impact of severe weather on their networks?

Yes
no
Don't know

ATTITUDES TOWARDS STANDARDS & TARGETS

Q 0 INTRO4
Ofgem, the regulator for the gas and electricity market, has put in place a number of standards which distributors are required to meet. If they fail to meet them then customers are entitled to compensation. I am going to run through some of the standards and ask a question about each?

Q 1 Q19
Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £100 for business consumers for the first 18 hrs plus £25 for each additional 12 hours.

Were you aware of this standard?

1 aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

Q 1 Q20
Consumers are entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year

Were you aware of this Standard?

1. aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

Q 1 Q21
Consumers must be given at least 2 days notice of a planned power cut. Failure to do so results in a penalty payment of £40 for business consumers.

Were you aware of this standard?

1. aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

S STATED PREFERENCE

Q 0 SPINTRO1A
I am now going to go through four exercises with you, each of which will look at your preferences for a number of **changes** that distribution companies could make to the service that they provide.

The first will look at:

the number of power cuts greater than 3 minutes experienced in rural areas over 5 years
the number of power cuts greater than 3 minutes experienced in urban areas over 5 years
and the average length of these power cuts.

Q 0 SPINTRO1C
You will be presented with six sets of choice pairs and will be asked in each case to say whether you prefer Option A or B. You may not like either, but please say which you would prefer in each instance.

* variable 1 DESIGN (Number of power cuts (3 mins) in rural areas over 5 years

More power cuts in rural areas:
- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA+1/2/3) over 5 years

The same number of power cuts in rural areas:
- ie an average of (DNO SPECIFIC DATA) in 5 years

Fewer power cuts in rural areas:
- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA –1/2/3)over 5 years

* variable 2 design (Number of power cuts (3 mins) in urban areas over 5 years

More power cuts in urban areas:
- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +1)over 5 years

The same number of power cuts in urban areas:
- ie an average (DNO SPECIFIC DATA) cuts in 5 years

Fewer power cuts in urban areas:
- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA -1)over 5 years

* variable 3 design (Average length of power cuts (3 mins) experienced by customers:)

Longer average power cut duration:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +5/10/15/20) minutes

No change in average power cut duration:- ie an average of (DNO SPECIFIC DATA) minutes

Shorter average power cut duration:- ie from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA – 5/10/15/20) minutes

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO2A
In this second exercise we are going to look at:

- the resilience of your local company's electricity system in a major storm
- provision of information during a power cut

You will see that in the resilience options we talk about your local company's electricity system being designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is reduced. Please note that 1% of your distributors customers is (DNO SPECIFIC DATA).

Q 0 SPINTRO2B
With this in mind, which of the following would you prefer?

* variable 1 DESIGN (electricity system)
Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is once a year, as now

Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm is **once every 2 years**, better than now

Your local company's electricity system will be designed and operated so that the likelihood of more than 1% of its customers losing power for more than 24 hours following a major storm **once every 5 years,** better than now

* variable 2 design (Provision of information)

Current level of information:
- (DNO SPECIFIC DATA) of callers receive information by automated message
(DNO SPECIFIC DATA) of callers are answered by a person on average in (DNO SPECIFIC DATA) seconds (this including some customers who have already heard an automated message)

Current level of information provision during a power cut, but with call backs by a person every 2 hours to provide updated information, if requested

A dedicated helpline for business customers with (DNO SPECIFIC DATA)of callers answered by a person (as now) but within half the current time

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO3A
We are now going to look at:

- the maximum time taken to restore customers following storms
- the number of UNPLANNED interruptions greater than 3 hours which would entitle you to a compensation payment
- compensation arrangements

Q 0 SPINTRO3B
When considering these options please be aware that, with respect to UNPLANNED interruptions greater than 3 hours, consumers are currently entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year.

And with respect to the compensation arrangements, please bear in mind that the current standard is as follows (and as shown in SHOWCARD A2 which has been sent to you):

INTERVIEWER: READ OUT

1Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £100 for business consumers for the first 18 hrs plus £25 for each additional 12 hours.

Q 0 SPINTRO3D
With this in mind, which of the following would you prefer?

Q 0 SPINTRO3E

INTERVIEWER: PLEASE REFER TO SHOWCARD A AND READ OUT THE DEFINITION OF 'HIGHER LEVEL OF COMPENSATION'.

* variable 1 DESIGN (Maximum time taken to restore customers following storms)

The maximum time taken to restore customers following storms would be within 60 hours, worse than now

The maximum time taken to restore customers following storms would be within 48 hours, as now

The maximum time taken to restore customers following storms would be within **36 hours**, better than now

The maximum time taken to restore customers following storms would be within **24 hours**, better than now

* variable 2 design (Number of UNPLANNED interruptions greater than 3 hours which entitles you to a compensation payment is:)

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be worse than now at 5 or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be as now, ie or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be better than now at 3 or more interruptions

* variable 3 design (Compensation under the 18 hour restoration standard)

Current compensation arrangements, ie £100 compensation for cuts greater than 18 hours and £25 for each additional 12 hours; compensation must be claimed

£100 compensation for cuts greater than 14 hours (rather than 18 hours) and **£25** for each additional 12 hours; **compensation must be claimed**

Compensation for cuts over 14 hours is the greater of **£100 and 2% of your annual electricity bill** and compensation for each additional 12 hours the greater of **£25 and 0.5% of your bill; compensation must be claimed**

Higher level of compensation; **compensation will be automatic**

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO4A
In this final exercise you will see both the best and worse options of all areas that we have just looked at in the first three exercises.

In addition, because no improvements would be possible without investment by the distribution companies – and consequently an increase in your electricity bill - you will also see the impact that the improvements shown would have on this site's overall electricity bill in year one and in subsequent years.

Bearing this in mind, we would once again like you to say which of the options you would prefer, A or B.

Q 0 SPINTRO4B

INTERVIEWER: PLEASE REFER TO SHOWCARD A AND READ OUT THE DEFINITION OF 'HIGHER LEVEL OF COMPENSATION'.

* variable 1 DESIGN (EXERCISE 1 LEVELS)
* level 1 best Ex 1 package

Fewer rural cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Fewer urban cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Shorter average cut duration: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA) minutes

* level 2 worst Ex 1 package

More rural cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

More urban cuts over 5 years: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA)

Longer average cut duraion: from (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA) minutes

* variable 2 design (EX 2 LEVELS)
* BEST PACKAGE GAME2

Likelihood of 1% customers losing power for 24 hours following a major storm is once every 5 years, better than now

A dedicated helpline for business customers with (DNO SPECIFIC DATA) of callers answered by a person (as now) but within half the current time

* WORST PACKAGE 2

Likelihood of 1% of customers losing power for 24 hours following a major storm is once a year, as now

Current level of information provision during a cut

* variable 3 design (EX 3 LEVELS)
* BEST EX 3 PACKAGE

Maximum restoration time following a storm better than now: within 24 hours

Number of **unplanned** interruptions 3 hours entitling you to compensation: better than now at 3 or more

Higher level of compensation; compensation will be automatic

* WORST EX 3 PACKAGE

Maximum restoration time following a storm worse than now: within 60 hours

Number of **unplanned**- interruptions 3 hours entitling you to compensation worse than now at 5 or more

Current compensation arrangements & compensation must be claimed

* VARIABLE 4 - COST
* LEVEL 1 - 1%-4% decreases
* LEVEL 2 - current
* LEVEL 3 - 1%-4% increases
* LEVEL 4 - 5%-8% increases

Your annual electricity bill would decrease from **CURRENT BILL** to **CURRENT BILL – LEVEL 1**

Your annual electricity bill would stay the same **CURRENT BILL**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 3**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 4**

Which choice would you prefer?
CHOICE A
CHOICE B

RELATIVE PRIORITIES

Q 1 Q22
Thank you for going through those exercises with me.

Could you now tell me how you would feel if you were to get an additional power cut over the next 12 months that you were not warned about? Please use a scale of 1 to 4, where 1 is equal to extremely unhappy, 2 to very unhappy, 3 to quite unhappy and 4 to indifferent.

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 10 Q23
And using the same scale, how would you feel if you were to get an additional power cut over the next 12 months that you were warned about?

Q 1 Q24

And how would you feel if the length of the power cut was to increase from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +20)MINS?

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 1 Q25
If you were to call your distribution company in the event of a power cut and were to receive an automated message providing information about the cut and measures being taken to address it, would you then prefer to hold for an operator to report the cut or receive further information, or would you prefer to be able to call back on a dedicated priority number. Calls to the dedicated number would be likely to be answered more quickly because of the smaller volume of calls to that number.

prefer to hold
prefer to call back
neither, auto message enough
don't know

DEMOGRAPHICS & CONTEXTUAL QUESTIONS

Q 1 Q26
Finally I would like to ask you a couple of questions to help with the analysis of this survey. How many sites (in the UK) does your company have?

one only
more than one
Don't know

Q 1 Q27
Under which of the following sectors would the activity of your company be classified?

READ OUT

1. Agriculture Forestry & Fishing
2. Mining
3. Construction
4. Manufacture Of Chemicals/Refining
5. Metal Goods And Engineering
6. Animal & Dairy Products & Vegetable processing
7. Manufacture of Miscellaneous Foods and Drink
8. Wholesale/Retail Distribution
9. Financial services
A. Pubs, Clubs, Restaurants and Hotels
B. Hospitals, Nursing and Medical Care
C. Education
D. Sport, Recreation and Other Personal Services
E. Central/local government
F. Professional services

Agriculture
Mining
Construction
Man. Chemicals
Metal Goods
Animal & Dairy
Man Misc. Foods
Wholesale/Retail
Financial services
Pubs, Clubs etc
Hospitals etc
Education
Sport etc

Central/local government
Prof services
Other (specify)

END OF INTERVIEW

Q 0 ThankU
THAT WAS THE LAST QUESTION.

Please can I take a note of your name and telephone number for quality control purposes

Q 2 NAME
Respondent name:

Q 2 WkTel
Work Telephone:

Q 0 END
That was the last question. Thank you very much for taking part in this research.

Q 1 RQ5
ENTER RESPONSE TO RQ Q4: Is the maximum electricity demand for the organisation:
1MW+
100KW - <1MW
<100KW
Don't know

Q 1 RQ6
ENTER RESPONSE TO RQ Q5: approximate cost of their annual electricity bill?
More than £159,000
£15,000-£159,000
<£15,000
Don't know
A not asked

Q 2 URN2

INTERVIEWER: PLEASE RE-ENTER URN FROM SAMPLE

Q 1 STATUS2

INTERVIEWER: PLEASE RE-ENTER WHETHER REAL OR PRACTICE INTERVIEW

real interview
practice interview

Q 1 MRSCODE

INTERVIEWER: DO YOU CONFIRM THAT THIS INTERVIEW WAS CONDUCTED UNDER THE TERMS OF THE MARKET RESEARCH SOCIETY CODE OF CONDUCT AND IS COMPLETELY CONFIDENTIAL

Yes
no

Phase 2 Main Business LPN

INTERVIEWER DETAILS

Q 1 STATUS

INTERVIEWER: IS THIS A REAL OR PRACTICE INTERVIEW?

real interview
practice interview

Q 3 INTNO

INTERVIEWER: PLEASE ENTER YOUR FOUR DIGIT INTERVIEWER NUMBER

L 1000
H 9999

Q 1 CHECK

DOES THE RESPONDENT HAVE THE SHOW MATERIAL TO HAND; PLEASE CHECK AND DO NOT PROCEED UNTIL THEY DO OR ARRANGE TO CALL THEM BACK

proceed

Q 1 SET
Can I confirm which set of showcards you have in front of you. The set number is shown in the header.

Set 1
Set 2
Set 3
Set 4
Set 5

Q 3 QNO

INTERVIEWER: PLEASE ENTER THE RECRUITMENT QUESTIONNAIRE NUMBER

L 1
H 9999

Q 2 URN

INTERVIEWER: PLEASE ENTER URN FROM SAMPLE

Q 1 SITE

INTERVIEWER: PLEASE ENTER RESPONSE TO Q1 ON THE RECRUITMENT QUESTIONNAIRE

head office
site

Q 2 SITE2
IF #SITE# EQ 2 GO TO DNO

INTERVIEWER: PLEASE TYPE IN TOWN AT WHICH THE SITE IN QUESTION IS LOCATED FROM Q1B ON THE RECRUITMENT QUESTIONNAIRE

Q 1 DNO

INTERVIEWER: PLEASE ENTER THE DNO AREA FROM WHICH SAMPLE IS DRAWN; SEE RQ

NOTE, IT CAN ONLY BE LPN FOR THIS QUESTIONNAIRE, IF IT IS ANY OTHER DNO YOU NEED TO CLOSE THIS QUESTIONNAIRE AND OPEN THE NORMAL BUSINESS QUESTIONNAIRE.

LPN (EDF)

MAIN INTERVIEW: Background

Q 0 INTRO
Thank you for agreeing to take part in this survey. As I have said, any answer you give will be treated in confidence in accordance with the Code of Conduct of the Market Research Society. You do not have to answer questions you do not wish to and you can terminate the interview at any point.

Q 2 POSTCODE1
IF #SITE# EQ 2 GO TO POSTCODE2
Can I begin by asking you for the first half of the postcode for the address of your site in #SITE2#, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg:
IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12
IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1

Q 2 POSTCODE2
IF #SITE# EQ 1 GO TO INTRO2
Can I begin by asking you for the first half of the postcode for your company's address, as this will help with our analysis.

INTERVIEWER: PLEASE ENTER THE FIRST HALF OF THE POSTCODE, eg:
IF FULL POSTCODE IS RG12 8QT PLEASE ENTER RG12
IF FULL POSTCODE IS RG1 5TT PLEASE ENTER RG1

Q 0 INTRO2
This interview is about electricity distribution rather than supply. In other words, it is about the company that runs the local network of wires or cables that transmit electricity, rather than the company that you pay the bills to. As you are probably aware, distributors are responsible for:

* restoring the power supply if there is a power cut
* operating a safety & security enquiry service for any problems with live cables
* connecting customers to their local network
* and investigating any complaints or problems that customers have regarding their electricity distribution service.

Q 5 ELECBILL
Can you please tell me what you pay each year for your electricity at this #SITE2# site?

INTERVIEWER: IT IS ESSENTIAL TO GET THIS INFORMATION. IF THE RESPONDENT KNOWS A MONTHLY AMOUNT MULTIPLY THIS BY 12; IF THEY KNOW A QUARTERLY AMOUNT MULTIPLY THIS BY 4 (BUT TRY TO GET A DISTINCTION BETWEEN WINTER AND SUMMER MONTHS AND CALCULATE ACCORDINGLY).

L 1
H 999999999

Q 1 BILLCHECK
Your electricity bill for the year is roughly, or exactly, #ELECBILL#. Is this correct?

Yes
No

IF #BILLCHECK# EQ 1 GO TO BILLCALC
IF #BILLCHECK# EQ 2 GO TO ELECBILL

Q 5 BILLCALC
V 5 BILLCAL
M BILLCAL [= #ELECBILL# P 25]
F 1 #BILLCAL#

Q 0 DISTBILL
About 25% of your current electricity bill currently goes towards electricity distribution, which means that, at this #SITE2# site, about #BILLCALC# of your annual bill goes towards distribution.

EXPERIENCES

Q 0 INTRO3
The remainder of this questionnaire is split into a number of sections. In the first section I would like to look at your experiences with respect to electricity distribution issues.

Firstly, can you tell me if you have experienced any of the following in the past 12 months at this #SITE2# site:

Q 1 Q1
Any unplanned power cuts lasting more than 3 minutes, ie any that you were ^C15not^C07 warned about?

Yes
No
Don't know/can't remember

Q 3 Q2
IF #Q1# NE 1 GO TO Q4
How many of these unplanned cuts have you had in the past twelve months?

NTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q3
On the last occasion that you had an unplanned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q4
And have you experienced any planned power cuts (ie ones that you were given advance warning of) lasting more than 3 minutes in the past 12 months at this #SITE2# site?

Yes
No
Don't know/can't remember

Q 3 Q5
IF #Q4# NE 1 GO TO Q7
How many of these planned cuts have you had in the past twelve months?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 3 Q6
On the last occasion that you had a planned power cut in excess of 3 minutes, how long did it last?

INTERVIEWER: RECORD IN MINUTES (eg 1 HOUR = 60, 2 HOURS 120 ETC); RECORD 9999 FOR DON'T KNOW
L 1
H 9999

Q 1 Q7
IF #Q1# NE 1 GO TO Q13

T On the last occasion that you experienced an unplanned power cut, did you try and contact your electricity distributor?

Yes
No
Don't know

Q 1 Q8
IF #Q7# NE 1 GO TO Q13
Did you manage to get through?

Yes
No
Don't know/can't remember

Q 3 Q9
IF #Q8# NE 1 GO TO Q13
How long did you take to get through initially, whether to an automated message or a person?

DO NOT PROMPT

INTERVIEWER: RECORD IN SECONDS; RECORD 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q10
Did you get an:

1. Automated message
2. Speak to someone
3. Both

Automated message
Spoke to someone
Both
Don't know/can't remember

Q 1 Q11
Did you get the information you wanted?

Yes
No
Don't know/can't remember

Q 1 Q12
IF #Q11# NE 1 GO TO Q13
Was the information about the power cut correct?

Yes
No
Don't know/can't remember

EXPECTATIONS ABOUT POWER SUPPLY

Q 1 Q13
Do you believe that it is reasonable for a power cut to occur in a major storm?

Yes
No
Don't know/not stated

Q 3 Q14

And what is the maximum number of unplanned power cuts lasting more than three hours that a company should be allowed in any one year before compensation is paid to their customers?

INTERVIEWER: ENTER 999 FOR DON'T KNOW

L 0
H 999

Q 1 Q15
In normal conditions, how quickly would you expect power to be restored following an unplanned power cut?

DO NOT PROMPT

1. within 1 hour
2. within 1-2 hours
2. within 2-3 hours
3. within 4-5 hours
4. within 6-10 hours
5. within 11-15 hours
6. within 16-18 hours
7. 18 hours or more

within 1 hour
1-2 hours
2-3 hours
4-5 hours
6-10 hours
11-15 hours
16-18 hours
18 hours or more
Don't know

Q 3 Q16
And in normal conditions, after how long (ie after how many hours of a power cut) should a distributor be required to pay compensation to a consumer?

INTERVIEWER: IF RESPONDENT SAYS "IMMEDIATELY" PLEASE ENTER "0

L 0
H 999

Q 3 Q17
If there had been a major storm affecting 1% of customers in your distribution company's area, how quickly would you expect power to be restored in such a case, to the nearest hour?

DO NOT PROMPT

ENTER RESPONSE IN HOURS; ENTER 999 FOR DON'T KNOW

L 1
H 999

Q 1 Q18
Do you think that distribution companies should be doing more to reduce the impact of severe weather on their networks?

Yes
No
Don't know

ATTITUDES TOWARDS STANDARDS & TARGETS

Q 0 INTRO4

Ofgem, the regulator for the gas and electricity market, has put in place a number of standards which distributors are required to meet. If they fail to meet them then customers are entitled to compensation. I am going to run through some of the standards and ask a question about each?

Q 1 Q19
Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £100 for business consumers for the first 18 hrs plus £25 for each additional 12 hours.

Were you aware of this standard?

1. aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

Q 1 Q20
Consumers are entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year

Were you aware of this Standard?

1. aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

Q 1 Q21
Consumers must be given at least 2 days notice of a planned power cut. Failure to do so results in a penalty payment of £40 for business consumers.

Were you aware of this standard?

1. aware of standard, but not amount of compensation
2. aware of standard & amount of compensation
3. unaware of standard or compensation

aware, but not of comp
aware of both
unaware

STATED PREFERENCE

Q 0 SPINTRO1A
I am now going to go through three exercises with you, each of which will look at your preferences for a number of **changes** that distribution companies could make to the service that they provide.

The first will look at:

- the number of power cuts greater than 3 minutes experienced in urban areas over 5 years
- the average length of these power cuts
- and the provision of information during a power cut.

Q 0 SPINTRO1B
You will be presented with six sets of choice pairs and will be asked in each case to say whether you prefer Option A or B. You may not like either, but please say which you would prefer in each instance.

* variable 1 design (Number of power cuts (3 mins) in urban areas over 5 years
More power cuts in urban areas:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA+1) over 5 years

The same number of power cuts in urban areas, - ie an average of (DNO SPECIFIC DATA) cuts in 5 years

Fewer power cuts in urban areas: - from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA -1) over 5 years

* variable 2 design (Average length of power cuts (3 mins) experienced by customers:)

Longer average power cut duration:- from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA +5/10/15/20) minutes

No change in average power cut duration:- ie an average of (DNO SPECIFIC DATA) minutes

Shorter average power cut duration:- ie from an average of (DNO SPECIFIC DATA) to (DNO SPECIFIC DATA – 5/10/15/20) minutes

Current level of information: **28%** of callers receive information by automated message **45%** of callers are answered by a person on average in **62** seconds (this including some customers who have already heard an automated message)

Current level of information provision during a power cut, **but with call backs by a person every 2 hours to provide updated information, if requested**

A **dedicated helpline for business customers** with **45%** of callers answered by a person (as now) but within half the current time

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO2A
In this second exercise we are going to look at:

the number of UNPLANNED interruptions greater than 3 hours which would entitle you to a compensation payment

compensation arrangements under the 18 hour restoration standard

---

Q 0 SPINTRO2B
When considering these options please be aware that, with respect to UNPLANNED interruptions greater than 3 hours, consumers are currently entitled to a penalty payment of £50 if they have 4 or more power cuts each longer than 3 hours in a single year.

And with respect to the compensation arrangements, please bear in mind that the current standard is as follows (and as shown in SHOWCARD A2 which has been sent to you):

INTERVIEWER: READ OUT

Distributors should restore consumers' supplies within 18 hours following unplanned interruptions. Failure to do so results in a penalty payment of £100 for business consumers for the first 18 hrs plus £25 for each additional 12 hours.

With this in mind, which of the following would you prefer?

Q 0 SPINTRO2C

INTERVIEWER: PLEASE REFER TO SHOWCARD A AND READ OUT THE DEFINITION OF 'HIGHER LEVEL OF COMPENSATION'.

* variable 1 design (Number of UNPLANNED interruptions greater than 3 hours which entitles you to a compensation payment is:)

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be worse than now at 5 or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be as now, ie or more interruptions

The number of **unplanned** interruptions greater than 3 hours which entitles you to a compensation payment would be better than 4 now at 3 or more interruptions

* variable 2 design (Compensation under the 18 hour restoration standard)
Current compensation arrangements, ie £100 compensation for cuts greater than 18 hours and £25 for each additional 12 hours; compensation must be claimed

£100 compensation for cuts greater than 14 hours (rather than 18 hours) and **£25** for each additional 12 hours; **compensation must be claimed**

Compensation for cuts over 14 hours is the greater of **£100 and 2% of your annual electricity bill** and compensation for each additional 12 hours the greater of **£25 and 0.5% of your bill; compensation must be claimed**

Higher level of compensation; **compensation will be automatic**

Which choice would you prefer?
CHOICE A
CHOICE B

Q 0 SPINTRO3A
In this final exercise you will see both the best and worse options of all areas that we have just looked at in the first two exercises.

In addition, because no improvements would be possible without investment by the distribution companies – and consequently an increase in your electricity bill - you will also see the impact that the improvements shown would have on this site's overall electricity bill in year one and in subsequent years.

Bearing this in mind, we would once again like you to say which of the options you would prefer, A or B.

Q 0 SPINTRO3B

INTERVIEWER: PLEASE REFER TO SHOWCARD A AND READ OUT THE DEFINITION OF 'HIGHER LEVEL OF COMPENSATION'.

GAME3A
* level 1 best Ex 1 package
Fewer urban cuts over 5 years: from 2 to 1

Shorter average cut duration: from 112 to 92 minutes

A dedicated helpline for business customers with 45% of callers answered by a person (as now) but within half the current time

* level 2 worst Ex 1 package
More urban cuts over 5 years: from 2 to 3

Longer average cut duration: from 112 to 132 minutes

Current level of information provision during a cut

* variable 2 design (EX 2 LEVELS)
* BEST PACKAGE GAME2
Number of **unplanned** interruptions 3 hours entitling you to compensation: better than now at 3 or more

Higher level of compensation; compensation will be automatic

* WORST PACKAGE 2
Number of **unplanned** interruptions 3 hours entitling you to compensation: worse than now at 5 or more

Current compensation arrangements & compensation must be claimed

* VARIABLE 3 - COST
* LEVEL 1 - 1%-4% decreases
* LEVEL 2 - current
* LEVEL 3 - 1%-4% increases
* LEVEL 4 - 5%-8% increases

Your annual electricity bill would decrease from **CURRENT BILL** to **CURRENT BILL – LEVEL 1**

Your annual electricity bill would stay the same **CURRENT BILL**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 3**

Your annual electricity bill would increase from **CURRENT BILL** to **CURRENT BILL + LEVEL 4**

Which choice would you prefer?
CHOICE A
CHOICE B

RELATIVE PRIORITIES

Q 1 Q22
Thank you for going through those exercises with me.

Could you now tell me how you would feel if you were to get an additional power cut over the next 12 months that you were not warned about? Please use a scale of 1 to 4, where 1 is equal to extremely unhappy, 2 to very unhappy, 3 to quite unhappy and 4 to indifferent.

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 10 Q23
And using the same scale, how would you feel if you were to get an additional power cut over the next 12 months that you were warned about?

Q 1 Q24
And how would you feel if the length of the power cut was to increase from an average of DNO SPECIFIC DATA to DNO SPECIFIC DATA +20 MINS?

extremely unhappy
very unhappy
quite unhappy
indifferent

Q 1 Q25
If you were to call your distribution company in the event of a power cut and were to receive an automated message providing information about the cut and measures being taken to address it, would you then prefer to hold for an operator to report the cut or receive further information, or would you prefer to be able to call back on a dedicated priority number. Calls to the dedicated number would be likely to be answered more quickly because of the smaller volume of calls to that number.

prefer to hold
prefer to call back
neither, auto message enough
Don't know

DEMOGRAPHICS & CONTEXTUAL QUESTIONS

Q 1 Q26
Finally I would like to ask you a couple of questions to help with the analysis of this survey. How many sites (in the UK) does your company have?

one only
more than one
Don't know

Q 1 Q27
Under which of the following sectors would the activity of your company be classified?

READ OUT

1. Agriculture Forestry & Fishing
2. Mining
3. Construction
4. Manufacture Of Chemicals/Refining
5. Metal Goods And Engineering
6. Animal & Dairy Products & Vegetable processing
7. Manufacture of Miscellaneous Foods and Drink
8. Wholesale/Retail Distribution
9. Financial services
A. Pubs, Clubs, Restaurants and Hotels
B. Hospitals, Nursing and Medical Care
C. Education
D. Sport, Recreation and Other Personal Services
E. Central/local government
F. Professional services
Agriculture
Mining
Construction
Man. Chemicals
Metal Goods
Animal & Dairy
Man Misc. Foods
Wholesale/Retail
Financial services
Pubs, Clubs etc
Hospitals etc
Education
Sport etc
Central/local government
Prof services
Other (specify)

END OF INTERVIEW

Q 0 ThankU
THAT WAS THE LAST QUESTION.

Please can I take a note of your name and telephone number for quality control purposes

---

Q 2 NAME
Respondent name:

Q 2 WkTel
Work Telephone:

Q 0 END
That was the last question. Thank you very much for taking part in this research.

Q 1 RQ5
ENTER RESPONSE TO RQ Q4: Is the maximum electricity demand for the organisation:

1MW+
100KW - <1MW
<100KW
Don't know

Q 1 RQ6
ENTER RESPONSE TO RQ Q5: approximate cost of their annual electricity bill?

More than £159,000
£15,000-£159,000
<£15,000
Don't know
Not asked

Q 2 URN2
INTERVIEWER: PLEASE RE-ENTER URN FROM SAMPLE

Q 1 STATUS2
INTERVIEWER: PLEASE RE-ENTER WHETHER REAL OR PRACTICE INTERVIEW

real interview
practice interview

Q 1 MRSCODE
INTERVIEWER: DO YOU CONFIRM THAT THIS INTERVIEW WAS CONDUCTED UNDER THE TERMS OF THE MARKET RESEARCH SOCIETY CODE OF CONDUCT AND IS COMPLETELY CONFIDENTIAL

Yes
No

APPENDIX D

Show Material

SHOWCARD B

GROUP 1: BEST OPTION

- Fewer power cuts in rural areas: from x to x (SEE SCREEN) over 5 years
- Fewer power cuts in urban areas: from x to x (SEE SCREEN) over 5 years
- Shorter average power cut duration: from x to x (SEE SCREEN) minutes

GROUP 1: WORST OPTION

- More power cuts in rural areas: from x to x (SEE SCREEN) over 5 years
- More power cuts in urban areas: from x to x (SEE SCREEN) over 5 years
- Longer average power cut duration: from x to x (SEE SCREEN) minutes

GROUP 2: BEST OPTION

- Likelihood of more than 1% of customers losing power for more than 24 hours following a major storm is once every 5 years, better than now
- Current level of information provision during a power cut, plus a dedicated helpline for customers dependent on medical equipment requiring an electricity supply
- An ongoing commitment to undergrounding x% of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

GROUP 2: WORST OPTION

- Likelihood of more than 1% of customers losing power for more than 24 hours following a major storm is once a year, as now
- Current level of information provision during a power cut
- No additional overhead lines to be undergrounded to reduce the visual impact of those lines

GROUP 3: BEST OPTION

- The maximum time taken to restore customers following storms would be within 24 hours, better than now
- The number of **unplanned** interruptions over 3 hours entitling you to compensation payments would be better than now at 3 or more
- There is automatic compensation for ALL interruption standards

GROUP 3: WORST OPTION

- The maximum time taken to restore customers following storms would be within 60 hours, worse than now
- The number of **unplanned** interruptions over 3 hours entitling you to compensation payments would be worse than now at 5 or more
- Current compensation arrangements would apply, ie customers have to claim compensation under all the interruption standards.

SHOWCARD B – LPN Only

GROUP 1: BEST OPTION

- Fewer power cuts in urban areas: from x to x (SEE SCREEN) over 5 years
- Shorter average power cut duration: from x to x (SEE SCREEN) minutes
- Current level of information provision during a power cut, plus a dedicated helpline for customers dependent on medical equipment requiring an electricity supply

GROUP 1: WORST OPTION

- More power cuts in urban areas: from x to x (SEE SCREEN) over 5 years
- Longer average power cut duration: from x to x (SEE SCREEN) minutes
- Current level of information provision during a power cut

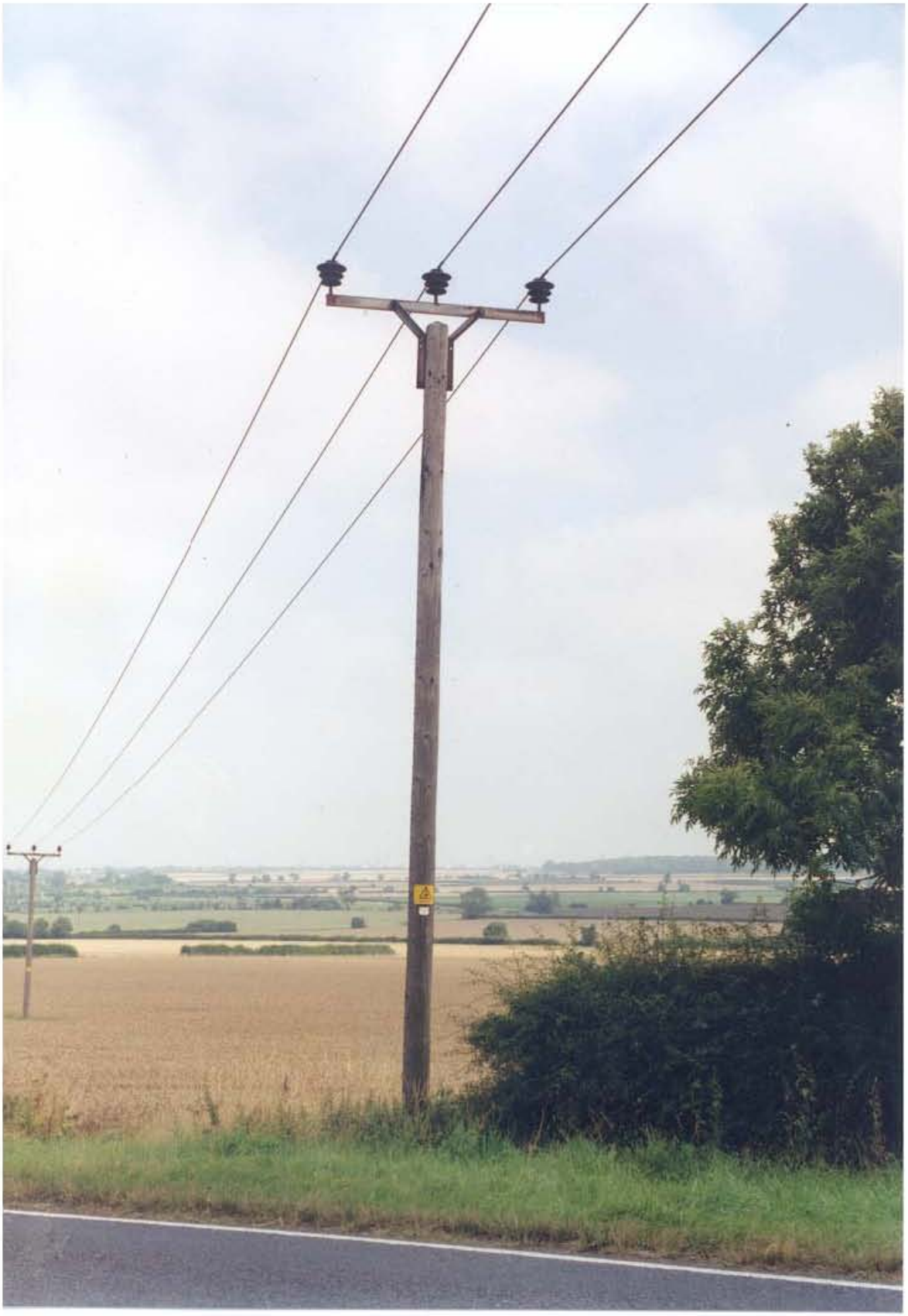
GROUP 2: BEST OPTION

- The number of **unplanned** interruptions over 3 hours entitling you to compensation payments would be better than now at 3 or more
- There is automatic compensation for ALL interruption standards
- An ongoing commitment to undergrounding x% of overhead lines per annum in areas of outstanding natural beauty and national parks until all are undergrounded

GROUP 2: WORST OPTION

- The number of **unplanned** interruptions over 3 hours entitling you to compensation payments would be worse than now at 5 or more
- Current compensation arrangements would apply, ie customers have to claim compensation under all the interruption standards.
- No additional overhead lines to be undergrounded to reduce the visual impact of those lines

SHOWCARD A



APPENDIX E

Individual DNO Business Results

Business WTP Values by individual DNO

Variable	Central Networks (West)	EDF Energy Networks (EPN)	Central Networks (East)	SP Manweb	NEDL	Scottish Hydro	Scottish Power	Southern Electric	EDF Energy Networks (SPN)	United Utilities	WPD (South Wales)	WPD (South West)	YEDL
Value per unplanned rural cut (reduction in frequency over 5 years from current)	0.56	0.00	0.00	1.59	0.00	0.00	1.66	0.00	0.00	0.00	1.19	0.00	0.00
Value per unplanned urban cut (reduction in frequency over 5 years from current)	3.48	3.94	3.25	4.87	4.12	0.00	9.75	2.48	5.35	8.14	2.65	3.37	5.61
Value per minute reduction to average cut	0.13	0.10	0.18	0.24	0.18	0.00	0.00	0.19	0.00	0.00	0.00	0.29	0.38
Reducing major cuts to one every 2 years	2.37	0.00	2.33	2.94	0.00	0.00	0.00	1.82	2.33	5.06	0.00	2.62	3.18
Reducing major cuts to one every 5 years	3.93	2.22	3.40	4.28	0.00	0.00	0.00	3.61	4.46	6.92	0.00	4.30	3.92
Call backs during outage if required	1.29	1.33	0.00	1.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.10
Helpline	0.00	0.00	0.00	2.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum restoration time 60 hours (decrement)	0.00	5.55	5.50	5.23	7.31	0.00	6.67	3.26	7.13	3.85	2.74	0.00	2.63
Maximum restoration time 36 hours (improvement)	3.98	7.56	2.03	8.57	11.33	0.00	7.28	6.03	2.42	4.89	7.22	6.42	5.53
Maximum restoration time 24 hours (improvement)	4.87	1.39	2.50	9.65	5.01	0.00	13.22	4.35	5.52	5.71	6.07	10.94	7.54
Compensation paid after 5 cuts (decrement)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.72	0.00	0.00	3.75	0.00
Compensation paid after 3 cuts (improvement)	1.96	1.95	0.00	0.00	0.00	0.00	0.00	1.74	0.00	2.65	3.95	0.00	4.13
Current compensation but after 14 hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Compensation after 14 hours based on bill size	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.01	0.00
Higher compensation paid automatically	1.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.80	0.00	0.00	0.00
Value of 20 minute reduction in average cut	2.54	1.94	3.54	4.78	3.59	0.00	0.00	3.88	0.00	0.00	0.00	5.78	7.66
Value of 40 minute reduction in average cut	5.08	3.89	7.09	9.56	7.17	0.00	0.00	7.76	0.00	0.00	0.00	11.55	15.31

Note: Cost coefficient for Scottish Hydro was insignificant so values cannot be derived

Economic Valuation of Electrical Service Reliability – Experiences from Austrian

Markus Bliem

Lisbon, 12 September 2008

Introduction

- Since 2001, the Austrian electricity market has been completely liberalised.
- Transmission and distribution networks represent a natural monopoly and must also be regulated.
- Since 2006, incentive regulation scheme (price-cap regulation).
- Price and quality are strong correlated. Economic theory predicts that where utilities are subjected to a price-cap it is profitable for them to reduce costs by cutting down on quality; a higher service reliability usually costs more money.
- In order to prevent a service quality deterioration you need a quality regulation scheme.

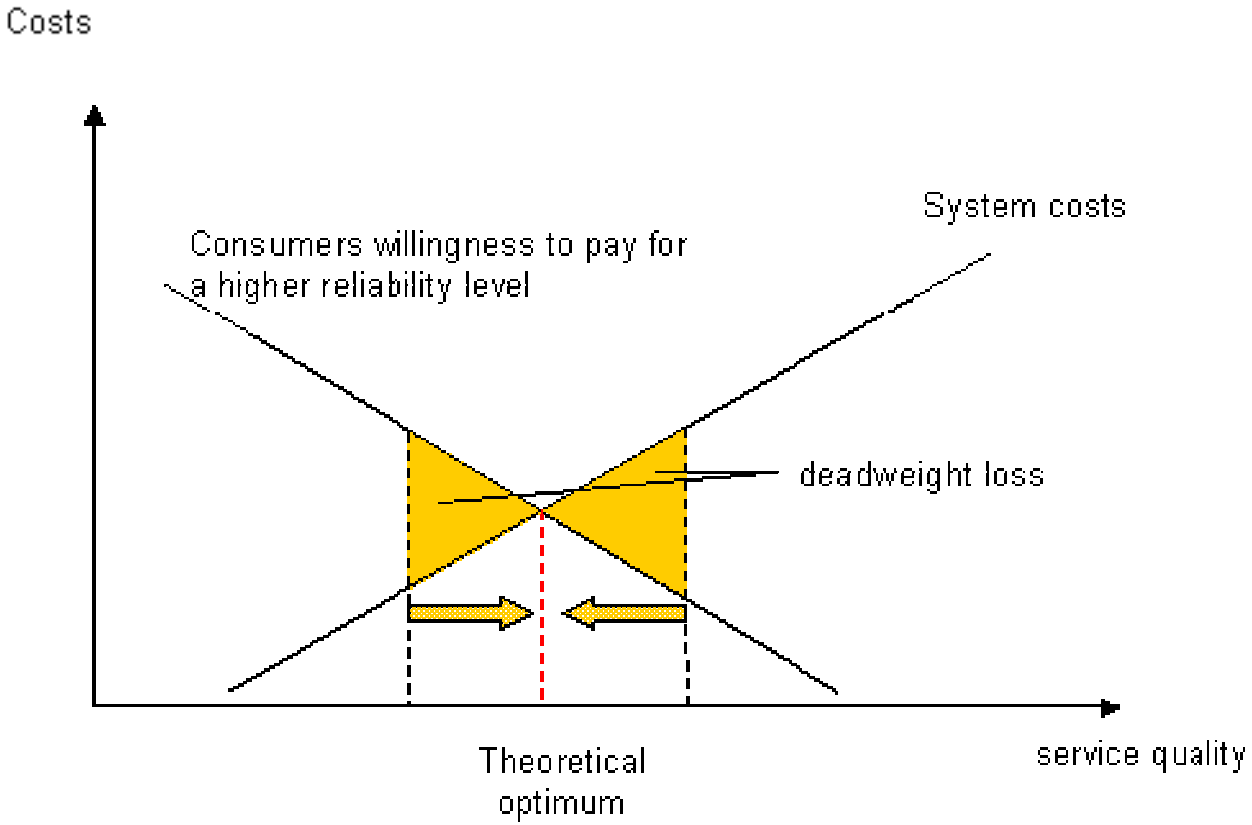
→ Problem: What is the optimal level of service quality?

Interruption costs as ‚reliability worth'

COST of providing quality and continuity of electric supply

=

BENEFIT of having a certain quality level and continuity of electric supply



Informational problems

Reaching this superior outcome is limited by different information problems:

1. Problem of measuring quality levels (most common measures are the so-called SAIDI and SAIFI).

2. Lacking information on consumer demand (expectations) for quality.

3. Lack of information on the (efficient) costs required to produce optimal quality.

Aims of the Thesis

- Apply stated preference methods to estimate the value of service reliability.
- The results of the survey were used to develop a regulation scheme that explicitly takes into account reliability of supply as the main quality dimension. How strongly will the Q-factor affect tariffs? The close relationship between actual performance level, the reference level and tariff was explored in detail by analysing some real-life examples.

Sample

- In order to guarantee a representative sample the survey covered all regions (districts) of Austria.

- Separate survey for households and companies.

  – Households: Sample was randomly generated using the electronic telephone book. → Sample size : **2,500 households**.

    Sample was weighted to reflect relevant socio-economic characteristics (age, gender, household size, etc.).

  – Business (SMEs and industry): Database Aurelia (Vienna University of Economics and Business Administration); Allocation of sample according to the number of companies in the Austrian "Bundesländer".

  – No sectoral classification. → Sample size : **1,500 companies.**

Questionnaire Logistics and Response Rate

- Postal survey in combination with a web-based survey was chosen.
- 2 Pre-tests in autumn 2006
- Final survey December 2006 - February 2007
- Recruitment-Screening for business customers: The challenge was to find a person who is responsible for the electrical service reliability and has the knowledge to appraise how the company would be affected by an outage.
- Incentive for households: successful use of a lottery!
- Total budget for the survey: € 6,000.-
- Funded by E-Control to cover direct costs for call centre, printing etc.; no personnel cost!

Table: Response Rate

	Sample	Responses	Response rate (%)
Households	2500	421	16.84
Business	1500	396	26.40
Total	4000	817	20.43

Questionnaire Design

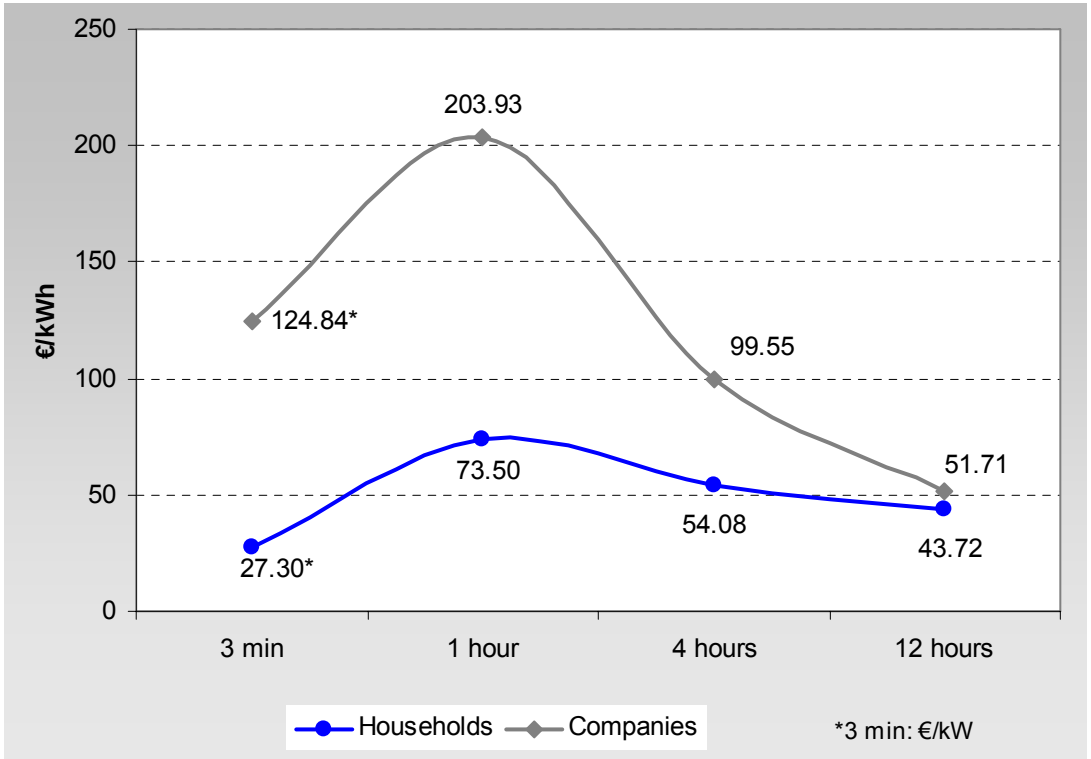
The questionnaire was developed to obtain information about:

- Direct economic interruption costs.
- The willingness to pay (WTP) to avoid a power outage of a certain duration.
- A choice experiment was carried out to identify the preferences that both groups of consumers have for improvements/deterioration in some service quality aspects.

Empirical Results - Direct Costs

In the survey, the respondents were asked to state their direct economic interruption costs of a certain duration at 2 pm on a working-day in summer. → scenario was chosen because it represents a worst case!

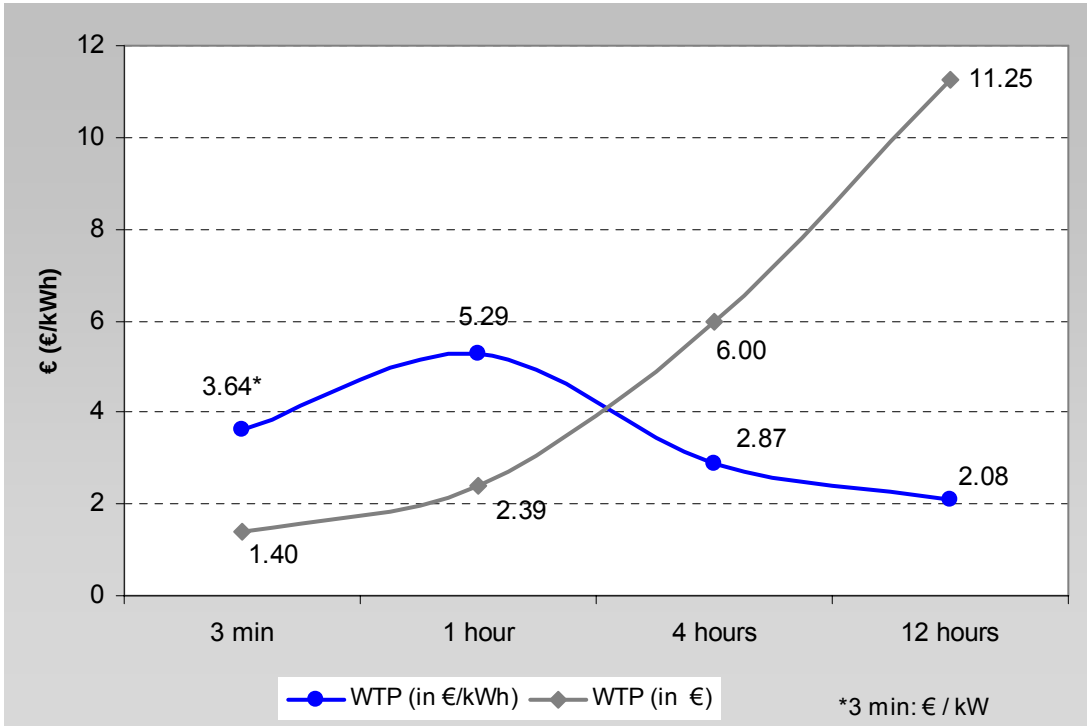
Figure: Direct costs (values are normalized with regard to the energy not supplied (€/kWh))



Empirical Results - CV I

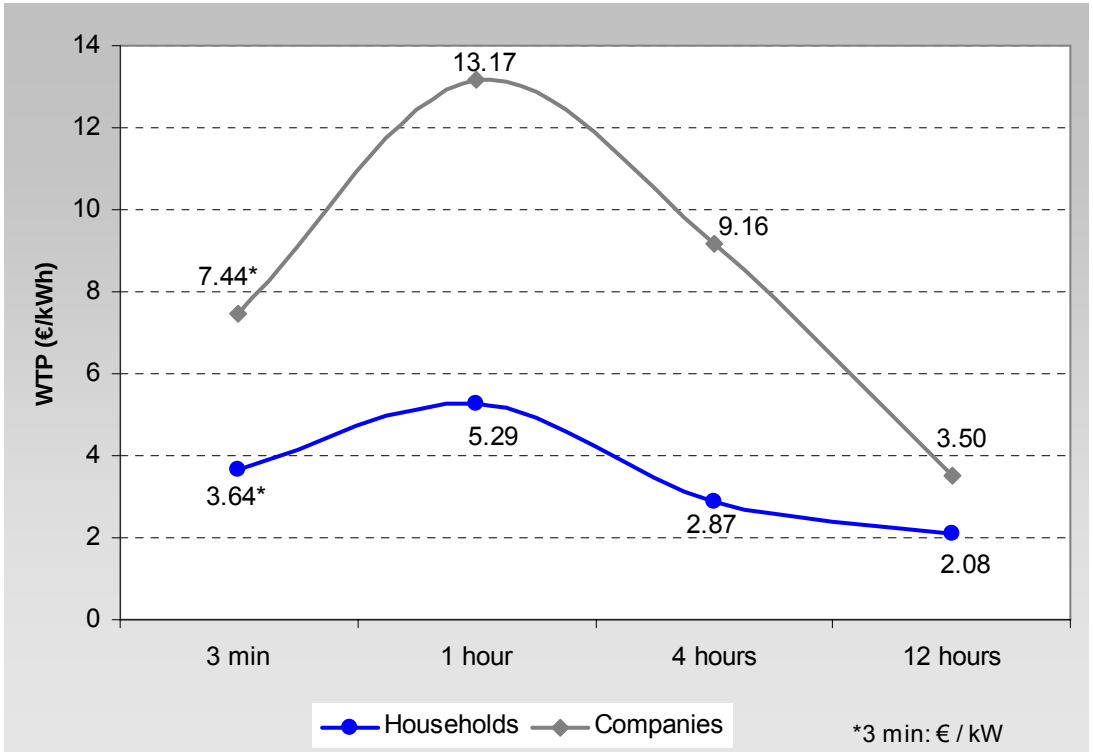
Households and commercial respondents were asked to state their maximum WTP for avoiding one power outage of a certain duration at 2 pm on a working-day in summer.

Figure: Normalized WTP for households



Empirical Results - CV II

Figure: WTP domestic and business electricity consumers (values are normalized with regard to the energy not supplied (€/kWh))



Comparison to existing studies I

Results are very similar to values for e.g. Italy or Sweden.

Table: WTP (€/kWh) for domestic and business electricity consumers in Austria and Italy (3 min. interruptions, €/kW)

	AUSTRIA		**ITALY***	
	Households	*Business*	*Households*	*Business*
3 min	3.64	7.44	1.38	4.90
1 hour	5.29	13.17	3.75	10.70
4 hours	2.87	9.16	2.25	6.63
8 hours	-	-	1.36	3.98
12 hours	2.08	3.50	-	-

*) Bertazzi, A.; Fumagalli, E. und Lo Schiavo, L. (2005). The Use of Customer Outage Cost Surveys in Policy Decision-Making: The Italian Experience in Regulating Quality of Electricity Supply. 18th International Conference on Electricity Distribution, Turin.

Comparison to existing studies II

Table: WTP for domestic electricity consumers in Austria and Sweden (€/outage)

	AUSTRIA	SWEDEN**
3 min	1.40	-
1 hour	2.39	1.02
4 hours	6.00	4.04
8 hours	-	11.76
12 hours	11.25	-
24 hours	-	24.26

**) Carlsson, F. und Martinsson, P. (2007). Willingness to Pay Among Swedish Households to Avoid Power Outages, A Random Parameter Tobit Model Approach, The Energy Journal 28, 75-89.

Divergence between direct costs and WTP

- Respondents have no personal experience with (long) power outages → lead to overestimation of direct costs.
- Most households do not experience any tangible economic losses when an interruption occurs → direct cost values are based on subjective issues, subjective expectations, subjective well-being.
- Strategic response from the respondents → overestimate their costs in the hope of directing more investments towards quality problems.
- ???

Choice Experiment Design and Application

• First step: Identify attributes; the range over which they vary must be set. The levels were presented as chances from the status quo!

• Second step: Define the monetary attribute to allow the estimation of WTP. Payment vehicle: Change in current electricity price.

• D-optimal design was used to combine the levels of the attributes into a number of alternatives (software JMP). The D-optimality criterion seeks to maximize the determinant of the information matrix, or to minimize the determinant of the variance-covariance matrix of the parameter estimators.

• 16 choice sets were randomly assigned to four blocks that a single respondent was confronted with four choice sets.

Attributes and Levels

Attribute	Level
duration (duration of outages in minutes/hours)	3 minutes, 30 minutes (current situation), 4 hours, 10 hours
frequency (number of outages per year)	0.5, 1 (current situation), 4, 10
time of day	Day, Night
day of the week	Tuesday, Sunday
advance notification of outage	None, yes
price (change in current bill)	No change, - 20 %, - 10 %, + 10 %

Choice Set Example

	Number of outages / year	Duration of outages	Day of the week	Time of day	Advanced notification	Change in current bill	I choose...
Option A	4 outages / year	4 hours	Tuesday	Night	no	-10 %	☐
Option B (Status quo)	1 outage / year	30 minutes	Tuesday	Day	no	No change	☐

In the choice experiment each choice set consisted of two options, one of which represented the 'status quo' (describing the current level of service reliability).

The level of the attributes included varied over all choice sets in alternative A, while alternative B represented the status quo.

Random-Effects-Probit Model – Households

Variable	Coefficient
Duration 3min	-0.114
	(0.117)
Duration 4h	-1.354**
	(0.165)
Duration 10h	-1.887**
	(0.153)
Frequency	-0.125**
	(0.014)
Price	-0.084**
	(0.007)
Time of day (night)	-0.061
	(0.119)
Day of the week (Sunday)	-0.617**
	(0.141)
Notification (yes)	0.237
	(0.124)
Working* frequency	-0.061*
	(0.027)
Working* Day of the week	0.325**
	(0.101)
Constant	0.220
	(0.128)
σ_v	0.725
ρ	0.344
Observations	1573
Number of nr	403
Wald Chi-squared(11) = 297.62	
* significant at 5%; ** significant at 1%	

Implicit Price - Households

Table: Implicit price estimates for households (in %)

Attribute	Coefficient	95 % Confidence Interval	
Duration 3min	-1.35	-4.05	1.33
Duration 4h	-16.07	-18.76	-13.37
Duration 10h	-22.38	-26.21	-18.55
Frequency	-1.49	-1.85	-1.12
Time of day (night)	-0.73	-3.46	1.99
Day of the week (Sunday)	-7.32	-9.94	-4.71
Notification (yes)	2.81	0.11	5.51

Random-Effects-Probit Model - Companies

Variable	Coefficient
Duration 3min	0.127
	(0.127)
Duration 4h	-0.272
	(0.162)
Duration 10h	-0.539**
	(0.142)
Frequency	-0.157**
	(0.028)
Price	-0.027**
	(0.006)
Time of day (night)	0.382**
	(0.142)
Day of the week (Sunday)	0.429**
	(0.148)
Notification (yes)	-0.056
	(0.137)
Precaution*duration	-0.096*
	(0.044)
satisfaction*frequency	0.035**
	(0.013)
Constant	-0.046
	(0.231)
σ_v	1.019
ρ	0.509
Observations	1468
Number of nr	367
Wald Chi-squared(10) = 143.94	
* significant at 5%; ** significant at 1%	

Implicit Price - Business

Table: Implicit price estimates for commercial respondents (in %)

Attribute	Coefficient	95 % Confidence Interval	
Duration 3min	4.64	-4.99	14.28
Duration 4h	-9.92	-19.30	-0.55
Duration 10h	-19.62	-30.85	-8.40
Frequency	-5.71	-8.81	-2.61
Time of day (night)	13.92	-0.44	28.30
Day of the week (Sunday)	15.64	-0.24	31.53
Notification (yes)	-2.03	-11.45	7.38

Some further considerations

• Results of the survey can be used to develop a regulation scheme that explicitly takes into account reliability of supply.

• In brief: the task of a penalty and reward system is to weight each temporal change of service reliability with consumers' marginal WTP thereby making it possible to internalize consumer preferences and WTP to avoid interruptions to the firm's decision-making-process.

• Utilities have the incentive to improve service reliability up to the point where the cost equals the consumers WTP for quality.

Proposal for a Quality Regulation Model

- Since 1 January 2006 Price-Cap Regulation (Systemnutzungstarife-Verordnung):

$$p_1 = p_0 \ (1 + NPI - X \pm Q)$$

where NPI is the net price index, X is the efficiency gain fixed by the regulator for a three year tariff period, and Q is a quality parameter.

- Currently, the Austrian Regulation Authority collects data on the frequency (SAIFI) and duration (SAIDI) of outages.

- Based on these statistics it is possible to derive an individual reference target for regulated utilities.

The Model I

- Yearly values of the parameter Q can be calculated, ex post, on the basis of company performances and relative financial incentives.

- Average reliability of network operator i over a period of M years, beginning in year T.

$$\overline{SAIDI}_{i,T,\ldots,T+M-1} = \frac{SAIDI_{i,T} + \ldots + SAIDI_{i,T+M-1}}{M}$$

SAIDI…System Average Interruption Duration Index [min/a]
i…system (grid) operator
M…given period
T…first year
$\overline{SAIDI}_i$ …moving average

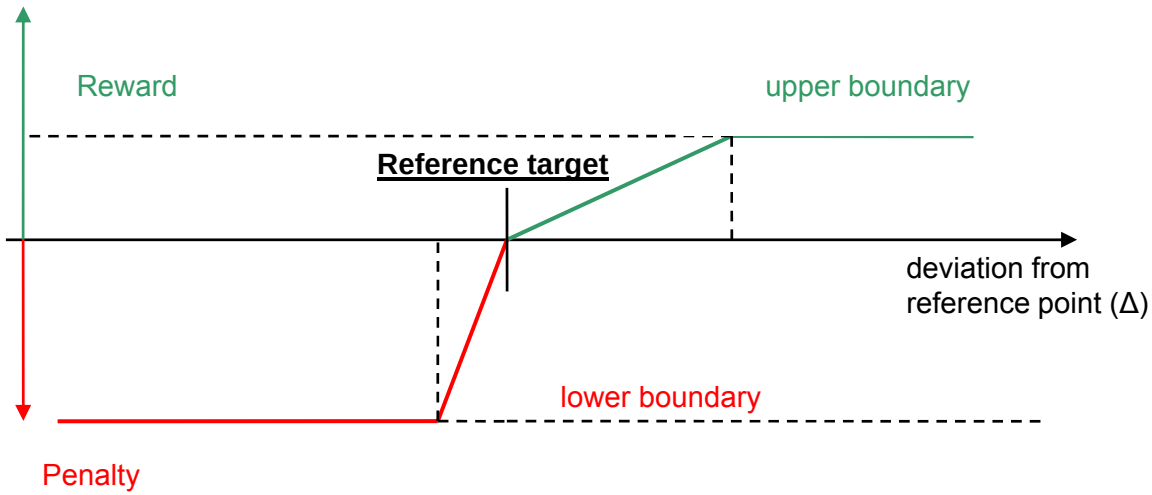
The Model II

- Quality-related company performances can be measured annually, as the difference (negative or positive) between the reference ($SAIDI_{ref}$) and a moving average of the measured SAIDI per each territorial district (Δ).

$$\Delta_{i,d} = SAIDI_{ref} - \overline{SAIDI}_{i,T,\ldots,T+M-1}$$

The Model III

Figure: Example of penalty or reward scheme



The level of reward or penalty depends on the deviation from the reliability target. If the actual level of reliability is higher than the individual reference target, the utility obtains a reward. If the actual level is lower than the reference target, the utility is penalised.

Thank you very much for your attention!

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How to Estimate the Value of Service Reliability Improvements

Michael J. Sullivan, Chairman, FSC, Matthew G. Mercurio, Senior Consultant, FSC, Josh A. Schellenberg, Senior Analyst, FSC, and Joseph H. Eto, Staff Scientist, LBNL

***Abstract*--A robust methodology for estimating the value of service reliability improvements is presented. Although econometric models for estimating value of service (interruption costs) have been established and widely accepted, analysts often resort to applying relatively crude interruption cost estimation techniques in assessing the economic impacts of transmission and distribution investments. This paper first shows how the use of these techniques can substantially impact the estimated value of service improvements. A simple yet robust methodology that does not rely heavily on simplifying assumptions is presented. When a smart grid investment is proposed, reliability improvement is one of the most frequently cited benefits. Using the best methodology for estimating the value of this benefit is imperative. By providing directions on how to implement this methodology, this paper sends a practical, usable message to the industry.**

***Index Terms*--Economics, education, planning, power distribution reliability, power system reliability, power transmission reliability, reliability, reliability estimation, statistics, technology planning**

I. Introduction

Reliability improvement is one of the most frequently cited justifications for investments in smart grid technology. Although reliability undoubtedly improves under most smart grid investments, the value of the reduction in outage frequency and/or duration is difficult to calculate. This difficulty leads many analysts to make simplifying assumptions. In a recent report by Freeman, Sullivan & Co. (FSC) and Lawrence Berkeley National Laboratory (LBNL), the authors propose a methodology for calculating the value of reliability improvements that does not as heavily rely on simplifying assumptions. This methodology has been proven to provide more reliable estimates, but has not usurped other methodologies because it is more complicated. This paper deals with that complication to guide analysts on how to apply outage cost estimates to a smart grid investment opportunity.

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II. Estimating Outage Costs

Starting in the mid-1980s, utilities in the US conducted a number of customer outage cost studies using slightly different survey methods and procedures. Survey-based methods have become the most widely used approach and are generally preferred over other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability and power quality conditions not observable using other techniques.[1] Commercial customers are asked about the value of lost production, other outage related costs, and outage related savings, after taking into account their ability to make up for any lost production. For residential customers, the vast share of outage impacts are not directly observable economic costs and, as a result, they are typically asked about their willingness to pay to avoid outages with specific characteristics. However, because most US utility companies believed these studies could be used by competitors and opponents in the regulatory arena to gain advantage, few of these studies were released to the public domain.

In 2008, the U.S. Department of Energy (DOE) funded a meta-study of outage costs, making the models to estimate outage costs publicly available and subsequently employed those models to estimate outage costs for U.S. electricity consumers [2]. Twenty-eight studies, conducted by 10 electric utilities between 1989 and 2005 representing residential and commercial and industrial (C&I) customer groups were included in the analysis. The data was used to estimate customer damage functions expressing customer outage costs as a function of duration, time of day, consumption, business type, and other factors. The functions can be used to calculate customized outage costs for specific customers and specific durations, allowing the estimation of outage cost for the average residential and commercial customer in a given area.

The publicly available customer damage functions in this study can be employed to estimate customer outage costs with and without a smart grid investment – i.e., with current outage average duration and frequency and with reduced outage

[1] Two other outage cost estimation techniques have been employed: scaled macro-economic indicators (i.e., gross domestic product, wages, etc.), and market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates). For a detailed explanation of the different approaches, see the "Outage Cost Estimation Guidebook" [1].

duration and frequency. Table 1 displays estimated average electricity customer interruption costs for 2008 expressed in costs per event, costs per average kW, costs per un-served kWh and costs per annual kWh. Cost estimates are provided for three customer segments and for durations ranging from less than 5 minutes (momentary) to 8 hours. They are reported for three customer classes defined as follows:

- Medium and Large C&l (all non-residential customers with sales greater than 50,000 kWh per year);
- Small C&l Customers (all non-residential accounts with sales less than or equal to 50,000 kWh per year), and;
- Residential customers.

The values in the table have been calculated using the general customer damage functions described. These customer damage functions and the results in Table 1 can be found in the report prepared for DOE by FSC and LBNL [2]. Section IV below explains how to apply these outage cost estimates to a smart grid investment opportunity.

TABLE I
ESTIMATED AVERAGE ELECTRIC CUSTOMER INTERRUPTION COSTS US 2008$ BY CUSTOMER TYPE AND DURATION

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

These customer damage functions are able to provide estimates of the costs of interruptions of varying duration; occurring at different times of day (morning, afternoon and evening), days of week (weekends or weekdays) and season (summer and winter). They also provide estimates of interruption costs for customers of different size; and in the case of business customers, by business type (i.e., retail, utilities, construction, etc.). It is also possible to estimate costs for planned as opposed to unannounced interruptions and for customers with and without backup generation. Thus by inserting reasonable assumptions about the interruption characteristics and customers into the customer damage functions, it is possible to use them to estimate the cost of a wide range of interruptions for a wide range of customers. Then the costs can be compared with and without a reliability investment to determine the change in value of service.

III. METHODOLOGICAL COMPARISON

There are two key findings from these outage cost estimates that have important implications for the valuation of smart grid investments:

1. Cost per un-served kWh is substantially higher for small C&I customers than medium and large C&I customers.
2. A reduction in outage duration is less valuable than a reduction in outage frequency if the reduction in un-served kWh is equal.

Depending on the customer mix in a given area or the types of technologies in consideration, analysts may drastically under- or overestimate the value of a smart grid investment if too many simplifying assumptions are made. The following two examples compare methodologies and consider the implications of these simplifying assumptions.

A. Value of Distribution Automation in California

In a recent report prepared for the California Energy Commission (CEC) [3], the authors investigate the value of a change in SAIFI that distribution automation investments in California will provide. These investments are projected to provide a 32.7 percent decrease in SAIFI where the average outage duration is 101.9 minutes. The estimated value to the customer is $127.7 million, of which $125.4 million comes from the C&I sector (see Table 2). To estimate this change in value of service, the C&I sector was split into commercial and industrial customers and assigned different dollar values per un-served kWh. Industrial customers were assumed to experience a loss of $25 per un-served kWh and $10 for commercial. The study that these values are based on is not reported.

However, as seen above, the more applicable C&I grouping methodology is between small C&I customers and medium and large C&I customers. Therefore, we take the combined C&I un-served kWh and allocate it among this alternative grouping. Based on usage data from a large California utility, we estimate that in California around 90 percent of C&I usage is among medium and large C&I customers and 10 percent among small C&I customers. Using this allocation and an approximate dollar per un-served kWh of a 101.9 minute outage, we estimate that the change in value of service is $239.6 million. This methodology leads to an estimated change in value of service nearly double that of the estimates in the CEC report.

TABLE II
ESTIMATING CHANGE IN VALUE OF SERVICE FROM AUTOMATED DISTRIBUTION INVESTMENTS IN CALIFORNIA – TWO METHODOLOGIES

C&I Grouping Methodology	Sector	Un-served kWh	$ / Un-served kWh	Change in Value of Service ($ million)
Commercial vs. Industrial	Commercial	1,655,688	$10.0	$16.6
	Industrial	4,305,287	$25.0	$107.6
	Combined C&I	**5,960,975**	**$20.8**	**$125.4**
Small C&I vs. Medium & Large C&I	Small C&I	596,098	$285.0	$169.9
	Medium & Large C&I	5,364,878	$13.0	$69.7
	Combined C&I	**5,960,975**	**$40.2**	**$239.6**

B. Problems with Un-served kWh Approach

Although we use the un-served kWh approach to compare differences in C&I groupings, this methodology does not deal

with the value of a reduction of outage duration and frequency separately. The second key finding from the aforementioned report is that a reduction in outage duration is less valuable than a reduction in outage frequency when the reduction in un-served kWh is equal. Therefore, the return on an investment that reduces outage frequency is greater than that of an investment that reduces outage duration, holding un-served kWh equal.

Consider this example. There are two smart grid investments in consideration. One reduces outage duration by 50 percent, and the other reduces outage frequency by 50 percent. Both reduce un-served kWh by 50 percent, but the value of each investment is quite different. Assume that in the base scenario, the average medium and large C&I customer experiences one 1-hour outage each year. In table 1 above, this 1-hour outage costs the customer $12,487 per year.

The investment that leads to a 50 percent reduction in outage duration will result in a situation where the average medium and large C&I customer still experiences one outage per year, but this outage is now 30 minutes. In Table 1 above, this 30-minute outage costs the customer $9,217 per year. In the end, the investment that reduces outage duration by 50 percent increases value of service by $3,270.

The investment that leads to a 50 reduction in outage frequency will result in a situation where the average outage duration is still 1-hour, but the probability of experiencing an outage is reduced by 50 percent. Therefore, a 1-hour outage still costs the customer $12,487, but since the probability of experiencing an outage in a given year is now 50 percent as opposed to 100 percent, the outage cost to the customer is now $6,244 per year. Although the reduction in un-served kWh is the same for both investments, the one that reduces outage frequency provides nearly double the value.

IV. How to Apply Outage Cost Estimates to a Smart Grid Investment Opportunity

Now that implications of the outage cost estimates in the report [2] have been discussed, this section summarizes the methodology for correctly applying them. The estimates were based on a two-part econometric regression model. In the first part, a Probit model is estimated to determine the probability that a given outage cost is greater than zero. The second part is a generalized linear model (GLM) that estimates outage cost given that it is greater than zero.

The data used for the two-part econometric regression model came from twenty-eight surveys conducted by 10 electric utilities between 1989 and 2005. Each survey was designed to estimate outage costs for residential and small, medium and large C&I customers. Each respondent was asked to estimate the cost of four to eight hypothetical outage scenarios of varying duration, time of year, day of week and time of day. For medium and large C&I customers, an extensive accounting of estimated costs was done. For residential and small C&I customers, respondents provided estimates of how much they would be willing to pay to avoid each outage scenario. The data for these twenty-eight surveys was standardized, adjusted for inflation and combined into the meta-dataset that was used to estimate the two-part model. There is substantial discussion in the methodology section of the report [2] as to why this two-part model is optimal. An extensive methodological discussion of the econometric techniques is beyond the scope of this paper.

Table 3 summarizes the regression coefficients and variables for both parts of the model. For each part of the model separately, the variable is multiplied by each coefficient and then totaled. Each of the totals is then transformed accordingly:

- For the Probit model, the sum of the cross products is run through the NORMSDIST() function in Microsoft Excel. This function always returns a value between zero and one, which is what the Probit is designed to do.
- For the GLM model, the sum of the cross products is run through the EXP() function in Microsoft Excel. Since the dependent variable in the GLM model was transformed by the natural log, it is necessary to exponentiate the initial GLM output.

After transforming the Probit output with NORMSDIST() and the GLM output with EXP(), the two numbers are multiplied together. In the end, this provides the probability that the outage cost is greater than zero (Probit) multiplied by the level of outage cost given that it is greater than zero (GLM). The result is the expected outage cost.

TABLE III
Regression Coefficients and Variables
Medium and Large C&I

Variable	Part of Model	
	Probit	GLM
Duration	0.0070	0.0091
Duration Squared	0.0000	0.0000
Morning	0.2002	0.0185
Afternoon	0.3805	0.2801
Evening	-0.0197	0.3058
Summer	0.4608	-0.0773
Weekday	0.1511	0.2522
Advanced Warning	0.0762	-0.0883
Natural Log of Annual MWh	0.0852	0.4509
Duration X lnMWh	-0.0002	-0.0002
Duration Squared X lnMWh	0.0000	0.0000
Mining	0.6854	0.4301
Construction	0.3760	1.5795
Manufacturing	0.5571	1.2892
Transportation, Communication & Utilities	0.1836	0.8146
Wholesale & Retail Trade	0.4550	0.2727
Finance, Insurance & Real Estate	0.2304	1.2249
Services	0.1642	0.5216
Public Administration	0.2069	0.6165
Industry Unknown	0.1502	1.0763
Backup generation or Power conditioning	0.0267	0.0804
Backup generation and Power conditioning	0.2651	0.1272
Constant	-1.7060	4.5241

Now that the calculation of the output has been discussed, it is necessary to explain each of the variables and what values to use for each:

- **Duration** – For the base scenario before the reliability

investment is made, duration is the current CAIDI. After the reliability investment is made, duration is the new CAIDI. All duration values are in minutes.

- **Duration squared** – Squared value of duration
- **Morning** – Probability that an outage occurs during the morning[4]
- **Afternoon** – Probability that an outage occurs during the afternoon[4]
- **Evening** – Probability that an outage occurs during the evening[2]
- **Summer** – Probability that an outage occurs during the summer months as opposed to non-summer months
- **Weekday** – Probability that an outage occurs on a weekday as opposed to the weekend
- **Advanced Warning** – Probability that advanced warning is given for an outage
- **Natural Log of Annual MWh** – Natural log of the annual MWh for the average customer
- **Duration X lnMWh** – Duration multiplied by the natural log of annual MWh
- **Duration Squared X lnMWh** – Duration squared multiplied by the natural log of annual MWh
- **Mining** through **Industry Unknown** – Percentage of customers that fall into each of these industry categories[3]
- **Backup generation or Power conditioning** – Percentage of customers that have backup generation or power conditioning equipment but not both[6]
- **Backup generation and Power conditioning** – Percentage of customers that have backup generation and power conditioning equipment[4]
- **Constant** – The constant is simply added into the sum of the cross products from the other variables and coefficients.

In order to calculate the cost per event values in Table 1 above, the average values in Table 4 are used. The expected outage conditions simply reflect the percentage of hours in the day, week and year that each scenario is taking place. Morning is 6 out of 24 hours in the day (25%). Afternoon and evening are 5 out of 24 hours in the day (20.8%). Summer is 4 out of 12 months in the year (33.3%). Weekday is 5 out of 7 days (71.4%). It is assumed that no advanced warning is given. If an outage is more likely to occur at a certain time, these values should be adjusted.

Ideally, analysts should base the expected outage conditions off of actual data. For a summer peaking utility, the summer variable should be a larger percentage to not only reflect the 4 months of summer in the year, but the fact that outages are more likely to occur during the summer. Historical data can be used to determine when outages are likely to occur, and the expected outage conditions can reflect those numbers. This method will provide the most accurate estimates for a given area.

The average customer characteristics should also be based off of actual data in a given area. The average annual MWh for a medium and large C&I customer is relatively straightforward to determine. The percentages for each industry reflect the industry mix in a given area. Finally, at least a rough estimate of the two backup generation and power conditioning variables should be used.

TABLE IV
INPUTS FOR OUTAGE COST REGRESSION

Variable	Average Value
Expected Outage Conditions	
Morning (6am to 12pm)	25.0%
Afternoon (12pm to 5pm)	20.8%
Evening (5pm to 10pm)	20.8%
Summer (June to September)	33.3%
Weekday	71.4%
Advanced Warning	0.0%
Average Customer Characteristics	
Annual MWh	7140.5
Mining	1.4%
Construction	0.9%
Manufacturing	28.6%
Transportation, Communication & Utilities	7.2%
Wholesale & Retail Trade	25.0%
Finance, Insurance & Real Estate	3.8%
Services	25.2%
Public Administration	1.8%
Industry Unknown	4.7%
Backup generation or Power conditioning	37.2%
Backup generation and Power conditioning	8.4%

An important step is to adjust the estimates for inflation. When the regressions were estimated, 2008 dollar values were used. This needs to be taken into consideration in the years to come. These 2008 dollar values can be adjusted by using readily available inflation indicators such as the Consumer Price Index or the GDP Deflator.

Once the outage cost has been calculated under the current CAIDI and the new CAIDI, the change in SAIFI needs to be accounted for also. The change in value of service is the expected annual outage cost under the current CAIDI and SAIFI minus the expected annual outage cost under the new CAIDI and SAIFI. This value must be multiplied by the total number of medium and large C&I customers to estimate the aggregate number. Since this is an annual estimate of the value of service, it needs to be multiplied by the number of years of useful life of the investment. A discount rate for future payments also needs to be taken into account.

Once the change in value of service has been calculated for

[2] The base scenario in the model is the probability that an outage occurs at night. This scenario is omitted from the regressions. The sum of the probabilities that an outage occurs during the morning, afternoon, evening and night must be 1.

[3] The base industry category in the model is Agriculture, Forestry and Fishing. This industry category must be accounted for so that all 10 industry categories total 100 percent.

[4] The base category is no backup generation or power conditioning equipment. The three categories must total 100 percent.

the medium and large C&I sector, the same must be done for the small C&I sector and the residential sector using the same methodology, but different models from the report [2]. The results will provide the most accurate estimate of the change in value of service that a given smart grid investment provides.

V. Conclusion

A recent study has shown that a change in the methodology for estimating the value of reliability improvements is needed. Nonetheless, many analysts continue to use other methodologies that more heavily rely on simplifying assumptions. Problems with these simplifying assumptions commonly arise in two situations:

1. When the C&I categorization is done incorrectly, or;
2. When un-served kWh is measured the same whether it results from outage duration or frequency.

This paper has shown that if these two issues are not accounted for, analysts may drastically under- or overestimate the change in value of service that results from a smart grid investment. By then explaining how to use the most current estimates of outage costs, it is hopeful that more analysts will employ this methodology.

VI. References

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VII. Biographies

Dr. Michael Sullivan is chairman and co-founder of Freeman, Sullivan & Co. He has published a number of works regarding customer response to service reliability issues. He is also a recognized authority in risk analysis and liability evaluation. He has extensive experience as an expert witness on issues of statistical analysis of product failure and construction defects, economic risks of claims and settlements, and economic models of future liability. In addition, Dr. Sullivan has pioneered the application of statistical and economic analysis disciplines, as well as the methodologies of survey and sample design to construction defect defense and to the management of product performance liabilities in the context of class action settlements and judgments.

Dr. Matthew Mercurio specializes in applied statistical analysis and econometric modeling. He has applied these skills to both public and private litigation, as well as other legal matters. Dr. Mercurio's skills and experience in applied statistical analysis include: analysis of longitudinal (panel) data, limited dependent and latent variables, analysis of time series data, including ARIMA modeling, event studies, forecasting, and simulation, and aurvey design and sampling analysis. Dr. Mercurio holds a Ph.D. in economics from Princeton University and a BA in Economics and Mathematics from Boston University.

Josh Schellenberg has been instrumental in developing impact evaluations for demand response programs at multiple utilities. In 2009, he evaluated California's Base Interruptible Program, which is one of the largest demand response resources in the United States with nearly 1 GW of load reduction capacity and participation from three large IOUs. He also played a key role in the econometric modeling for the ex-post evaluation of Pacific Gas & Electric's SmartRate program, which was one of the largest deployments of CPP in the country. Concurrently, Mr. Schellenberg has worked on each of the annual evaluations of Southern California Edison's demand response portfolio since 2008.

Joseph Eto is a staff scientist in the Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory. His principal responsibility is management of the Consortium for Electric Reliability Technology Solutions, which is coordinating multi-institution, public-interest research to maintain and enhance the reliability of power systems during the transition to restructured electricity markets. Mr. Eto has authored over 150 publications on electricity policy, electricity reliability, transmission planning, cost-allocation, demand response, distributed energy resources, utility integrated resource planning, demand-side management, and building energy-efficiency technologies and markets.

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Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

These customer damage functions are able to provide estimates of the costs of interruptions of varying duration; occurring at different times of day (morning, afternoon and evening), days of week (weekends or weekdays) and season (summer and winter). They also provide estimates of interruption costs for customers of different size; and in the case of business customers, by business type (i.e., retail, utilities, construction, etc.). It is also possible to estimate costs for planned as opposed to unannounced interruptions and for customers with and without backup generation. Thus by inserting reasonable assumptions about the interruption characteristics and customers into the customer damage functions, it is possible to use them to estimate the cost of a wide range of interruptions for a wide range of customers. Then the costs can be compared with and without a reliability investment to determine the change in value of service.

III. METHODOLOGICAL COMPARISON

There are two key findings from these outage cost estimates that have important implications for the valuation of smart grid investments:

1. Cost per un-served kWh is substantially higher for small C&I customers than medium and large C&I customers.
2. A reduction in outage duration is less valuable than a reduction in outage frequency if the reduction in un-served kWh is equal.

Depending on the customer mix in a given area or the types of technologies in consideration, analysts may drastically under- or overestimate the value of a smart grid investment if too many simplifying assumptions are made. The following two examples compare methodologies and consider the implications of these simplifying assumptions.

A. Value of Distribution Automation in California

In a recent report prepared for the California Energy Commission (CEC) [3], the authors investigate the value of a change in SAIFI that distribution automation investments in California will provide. These investments are projected to provide a 32.7 percent decrease in SAIFI where the average outage duration is 101.9 minutes. The estimated value to the customer is $127.7 million, of which $125.4 million comes from the C&I sector (see Table 2). To estimate this change in value of service, the C&I sector was split into commercial and industrial customers and assigned different dollar values per un-served kWh. Industrial customers were assumed to experience a loss of $25 per un-served kWh and $10 for commercial. The study that these values are based on is not reported.

However, as seen above, the more applicable C&I grouping methodology is between small C&I customers and medium and large C&I customers. Therefore, we take the combined C&I un-served kWh and allocate it among this alternative grouping. Based on usage data from a large California utility, we estimate that in California around 90 percent of C&I usage is among medium and large C&I customers and 10 percent among small C&I customers. Using this allocation and an approximate dollar per un-served kWh of a 101.9 minute outage, we estimate that the change in value of service is $239.6 million. This methodology leads to an estimated change in value of service nearly double that of the estimates in the CEC report.

TABLE II
ESTIMATING CHANGE IN VALUE OF SERVICE FROM AUTOMATED DISTRIBUTION INVESTMENTS IN CALIFORNIA – TWO METHODOLOGIES

C&I Grouping Methodology	Sector	Un-served kWh	$ / Un-served kWh	Change in Value of Service ($ million)
Commercial vs. Industrial	Commercial	1,655,688	$10.0	$16.6
	Industrial	4,305,287	$25.0	$107.6
	Combined C&I	**5,960,975**	**$20.8**	**$125.4**
Small C&I vs. Medium & Large C&I	Small C&I	596,098	$285.0	$169.9
	Medium & Large C&I	5,364,878	$13.0	$69.7
	Combined C&I	**5,960,975**	**$40.2**	**$239.6**

B. Problems with Un-served kWh Approach

Although we use the un-served kWh approach to compare differences in C&I groupings, this methodology does not deal

with the value of a reduction of outage duration and frequency separately. The second key finding from the aforementioned report is that a reduction in outage duration is less valuable than a reduction in outage frequency when the reduction in un-served kWh is equal. Therefore, the return on an investment that reduces outage frequency is greater than that of an investment that reduces outage duration, holding un-served kWh equal.

Consider this example. There are two smart grid investments in consideration. One reduces outage duration by 50 percent, and the other reduces outage frequency by 50 percent. Both reduce un-served kWh by 50 percent, but the value of each investment is quite different. Assume that in the base scenario, the average medium and large C&I customer experiences one 1-hour outage each year. In table 1 above, this 1-hour outage costs the customer $12,487 per year.

The investment that leads to a 50 percent reduction in outage duration will result in a situation where the average medium and large C&I customer still experiences one outage per year, but this outage is now 30 minutes. In Table 1 above, this 30-minute outage costs the customer $9,217 per year. In the end, the investment that reduces outage duration by 50 percent increases value of service by $3,270.

The investment that leads to a 50 reduction in outage frequency will result in a situation where the average outage duration is still 1-hour, but the probability of experiencing an outage is reduced by 50 percent. Therefore, a 1-hour outage still costs the customer $12,487, but since the probability of experiencing an outage in a given year is now 50 percent as opposed to 100 percent, the outage cost to the customer is now $6,244 per year. Although the reduction in un-served kWh is the same for both investments, the one that reduces outage frequency provides nearly double the value.

IV. How to Apply Outage Cost Estimates to a Smart Grid Investment Opportunity

Now that implications of the outage cost estimates in the report [2] have been discussed, this section summarizes the methodology for correctly applying them. The estimates were based on a two-part econometric regression model. In the first part, a Probit model is estimated to determine the probability that a given outage cost is greater than zero. The second part is a generalized linear model (GLM) that estimates outage cost given that it is greater than zero.

The data used for the two-part econometric regression model came from twenty-eight surveys conducted by 10 electric utilities between 1989 and 2005. Each survey was designed to estimate outage costs for residential and small, medium and large C&I customers. Each respondent was asked to estimate the cost of four to eight hypothetical outage scenarios of varying duration, time of year, day of week and time of day. For medium and large C&I customers, an extensive accounting of estimated costs was done. For residential and small C&I customers, respondents provided estimates of how much they would be willing to pay to avoid each outage scenario. The data for these twenty-eight surveys was standardized, adjusted for inflation and combined into the meta-dataset that was used to estimate the two-part model. There is substantial discussion in the methodology section of the report [2] as to why this two-part model is optimal. An extensive methodological discussion of the econometric techniques is beyond the scope of this paper.

Table 3 summarizes the regression coefficients and variables for both parts of the model. For each part of the model separately, the variable is multiplied by each coefficient and then totaled. Each of the totals is then transformed accordingly:

- For the Probit model, the sum of the cross products is run through the NORMSDIST() function in Microsoft Excel. This function always returns a value between zero and one, which is what the Probit is designed to do.
- For the GLM model, the sum of the cross products is run through the EXP() function in Microsoft Excel. Since the dependent variable in the GLM model was transformed by the natural log, it is necessary to exponentiate the initial GLM output.

After transforming the Probit output with NORMSDIST() and the GLM output with EXP(), the two numbers are multiplied together. In the end, this provides the probability that the outage cost is greater than zero (Probit) multiplied by the level of outage cost given that it is greater than zero (GLM). The result is the expected outage cost.

TABLE III
Regression Coefficients and Variables
Medium and Large C&I

Variable	Part of Model	
	Probit	GLM
Duration	0.0070	0.0091
Duration Squared	0.0000	0.0000
Morning	0.2002	0.0185
Afternoon	0.3805	0.2801
Evening	-0.0197	0.3058
Summer	0.4608	-0.0773
Weekday	0.1511	0.2522
Advanced Warning	0.0762	-0.0883
Natural Log of Annual MWh	0.0852	0.4509
Duration X lnMWh	-0.0002	-0.0002
Duration Squared X lnMWh	0.0000	0.0000
Mining	0.6854	0.4301
Construction	0.3760	1.5795
Manufacturing	0.5571	1.2892
Transportation, Communication & Utilities	0.1836	0.8146
Wholesale & Retail Trade	0.4550	0.2727
Finance, Insurance & Real Estate	0.2304	1.2249
Services	0.1642	0.5216
Public Administration	0.2069	0.6165
Industry Unknown	0.1502	1.0763
Backup generation or Power conditioning	0.0267	0.0804
Backup generation and Power conditioning	0.2651	0.1272
Constant	-1.7060	4.5241

Now that the calculation of the output has been discussed, it is necessary to explain each of the variables and what values to use for each:

- **Duration** – For the base scenario before the reliability

investment is made, duration is the current CAIDI. After the reliability investment is made, duration is the new CAIDI. All duration values are in minutes.

- **Duration squared** – Squared value of duration
- **Morning** – Probability that an outage occurs during the morning[4]
- **Afternoon** – Probability that an outage occurs during the afternoon[4]
- **Evening** – Probability that an outage occurs during the evening[2]
- **Summer** – Probability that an outage occurs during the summer months as opposed to non-summer months
- **Weekday** – Probability that an outage occurs on a weekday as opposed to the weekend
- **Advanced Warning** – Probability that advanced warning is given for an outage
- **Natural Log of Annual MWh** – Natural log of the annual MWh for the average customer
- **Duration X lnMWh** – Duration multiplied by the natural log of annual MWh
- **Duration Squared X lnMWh** – Duration squared multiplied by the natural log of annual MWh
- **Mining** through **Industry Unknown** – Percentage of customers that fall into each of these industry categories[3]
- **Backup generation or Power conditioning** – Percentage of customers that have backup generation or power conditioning equipment but not both[6]
- **Backup generation and Power conditioning** – Percentage of customers that have backup generation and power conditioning equipment[4]
- **Constant** – The constant is simply added into the sum of the cross products from the other variables and coefficients.

In order to calculate the cost per event values in Table 1 above, the average values in Table 4 are used. The expected outage conditions simply reflect the percentage of hours in the day, week and year that each scenario is taking place. Morning is 6 out of 24 hours in the day (25%). Afternoon and evening are 5 out of 24 hours in the day (20.8%). Summer is 4 out of 12 months in the year (33.3%). Weekday is 5 out of 7 days (71.4%). It is assumed that no advanced warning is given. If an outage is more likely to occur at a certain time, these values should be adjusted.

Ideally, analysts should base the expected outage conditions off of actual data. For a summer peaking utility, the summer variable should be a larger percentage to not only reflect the 4 months of summer in the year, but the fact that outages are more likely to occur during the summer. Historical data can be used to determine when outages are likely to occur, and the expected outage conditions can reflect those numbers. This method will provide the most accurate estimates for a given area.

The average customer characteristics should also be based off of actual data in a given area. The average annual MWh for a medium and large C&I customer is relatively straightforward to determine. The percentages for each industry reflect the industry mix in a given area. Finally, at least a rough estimate of the two backup generation and power conditioning variables should be used.

TABLE IV
INPUTS FOR OUTAGE COST REGRESSION

Variable	Average Value
Expected Outage Conditions	
Morning (6am to 12pm)	25.0%
Afternoon (12pm to 5pm)	20.8%
Evening (5pm to 10pm)	20.8%
Summer (June to September)	33.3%
Weekday	71.4%
Advanced Warning	0.0%
Average Customer Characteristics	
Annual MWh	7140.5
Mining	1.4%
Construction	0.9%
Manufacturing	28.6%
Transportation, Communication & Utilities	7.2%
Wholesale & Retail Trade	25.0%
Finance, Insurance & Real Estate	3.8%
Services	25.2%
Public Administration	1.8%
Industry Unknown	4.7%
Backup generation or Power conditioning	37.2%
Backup generation and Power conditioning	8.4%

An important step is to adjust the estimates for inflation. When the regressions were estimated, 2008 dollar values were used. This needs to be taken into consideration in the years to come. These 2008 dollar values can be adjusted by using readily available inflation indicators such as the Consumer Price Index or the GDP Deflator.

Once the outage cost has been calculated under the current CAIDI and the new CAIDI, the change in SAIFI needs to be accounted for also. The change in value of service is the expected annual outage cost under the current CAIDI and SAIFI minus the expected annual outage cost under the new CAIDI and SAIFI. This value must be multiplied by the total number of medium and large C&I customers to estimate the aggregate number. Since this is an annual estimate of the value of service, it needs to be multiplied by the number of years of useful life of the investment. A discount rate for future payments also needs to be taken into account.

Once the change in value of service has been calculated for

[2] The base scenario in the model is the probability that an outage occurs at night. This scenario is omitted from the regressions. The sum of the probabilities that an outage occurs during the morning, afternoon, evening and night must be 1.

[3] The base industry category in the model is Agriculture, Forestry and Fishing. This industry category must be accounted for so that all 10 industry categories total 100 percent.

[4] The base category is no backup generation or power conditioning equipment. The three categories must total 100 percent.

the medium and large C&I sector, the same must be done for the small C&I sector and the residential sector using the same methodology, but different models from the report [2]. The results will provide the most accurate estimate of the change in value of service that a given smart grid investment provides.

V. Conclusion

A recent study has shown that a change in the methodology for estimating the value of reliability improvements is needed. Nonetheless, many analysts continue to use other methodologies that more heavily rely on simplifying assumptions. Problems with these simplifying assumptions commonly arise in two situations:

1. When the C&I categorization is done incorrectly, or;
2. When un-served kWh is measured the same whether it results from outage duration or frequency.

This paper has shown that if these two issues are not accounted for, analysts may drastically under- or overestimate the change in value of service that results from a smart grid investment. By then explaining how to use the most current estimates of outage costs, it is hopeful that more analysts will employ this methodology.

VI. References

[1] M. J. Sullivan, and D. M. Keane. "Outage Cost Estimation Guidebook," *EPRI Research Project 2878-04 Final Report*, December 1995.

[2] M. J. Sullivan, M. G. Mercurio, and J. A. Schellenberg. "Estimated Value of Service Reliability for Electric Utility Customers in the United States," *LBNL Research Project Final Report*, June 2009.

[3] S. Blazewicz, G. Shlatz, F. Small, S. Tobias, and J. Bean. "The Value of Distribution Automation," *California Energy Commission Research Project CEC-500-2007-103 Final Report*, March 2009.

VII. Biographies

Dr. Michael Sullivan is chairman and co-founder of Freeman, Sullivan & Co. He has published a number of works regarding customer response to service reliability issues. He is also a recognized authority in risk analysis and liability evaluation. He has extensive experience as an expert witness on issues of statistical analysis of product failure and construction defects, economic risks of claims and settlements, and economic models of future liability. In addition, Dr. Sullivan has pioneered the application of statistical and economic analysis disciplines, as well as the methodologies of survey and sample design to construction defect defense and to the management of product performance liabilities in the context of class action settlements and judgments.

Dr. Matthew Mercurio specializes in applied statistical analysis and econometric modeling. He has applied these skills to both public and private litigation, as well as other legal matters. Dr. Mercurio's skills and experience in applied statistical analysis include: analysis of longitudinal (panel) data, limited dependent and latent variables, analysis of time series data, including ARIMA modeling, event studies, forecasting, and simulation, and aurvey design and sampling analysis. Dr. Mercurio holds a Ph.D. in economics from Princeton University and a BA in Economics and Mathematics from Boston University.

Josh Schellenberg has been instrumental in developing impact evaluations for demand response programs at multiple utilities. In 2009, he evaluated California's Base Interruptible Program, which is one of the largest demand response resources in the United States with nearly 1 GW of load reduction capacity and participation from three large IOUs. He also played a key role in the econometric modeling for the ex-post evaluation of Pacific Gas & Electric's SmartRate program, which was one of the largest deployments of CPP in the country. Concurrently, Mr. Schellenberg has worked on each of the annual evaluations of Southern California Edison's demand response portfolio since 2008.

Joseph Eto is a staff scientist in the Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory. His principal responsibility is management of the Consortium for Electric Reliability Technology Solutions, which is coordinating multi-institution, public-interest research to maintain and enhance the reliability of power systems during the transition to restructured electricity markets. Mr. Eto has authored over 150 publications on electricity policy, electricity reliability, transmission planning, cost-allocation, demand response, distributed energy resources, utility integrated resource planning, demand-side management, and building energy-efficiency technologies and markets.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 15:

Reference(s): Exhibit 2B, Section D3, page 14

Preamble:

As part of on-going enhancements to the Feeder Investment Model, Toronto Hydro is planning to conduct a CIC study to provide more specific breakdown of CIC values within the FIM.

a) Please provide an estimate of timing when Toronto Hydro will be conducting a CIC study? When will this study be completed?

b) Has Toronto Hydro conducted any CIC studies after Ex-2012-0064 and up to this point in time? If yes, please provide a copy of such studies. If no, why not?

c) Has Toronto Hydro conducted any refining of the FIM inputs from Ex-2012-0064 and up to this point in time? If so, please provide the changes and explain?

RESPONSE:

a) Please refer to Section E8.8.4 of the Distribution System Plan (Exhibit 2B, Section E8.8, page 12) for specific information regarding the undertaking and completion of the CIC valuation study.

b) No, THESL has not conducted any CIC studies following the EB-2012-0064 application. Please refer to the response to interrogatory 2B-AMPCO-13 part (c) for incremental work accomplished towards the completion of such a study.

c) Please refer to response to interrogatory 2B-AMPCO-13 part (b).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 16:

Reference(s): Exhibit 2B, Section D3, page 14

Preamble:

In these values [customer interruption costs] on a kVa and kVA-hour basis, no distinctions are made between customer by customer classes.

a) Please discuss why no distinctions are made between customer classes when determining customer interruption costs?

RESPONSE:

a) Toronto Hydro explained this extensively in EB-2012-0064. These explanations are summarized in the following excerpt from Toronto Hydro's Reply Argument in that proceeding:

221. In any event, the average interruption costs that Toronto Hydro uses are on a per kVA basis. This necessarily means that the interruption costs used for larger customers with larger loads are greater than those for residential customers with smaller loads. For example, using the values in the FIM a two-hour outage for a large 3,000 kVA customer would be valued at $180,000 while that same outage for a 1.5kVA residential customer would be valued at $90. Thus while further refinements to the FIM may be possible, the interruption costs currently employed in the model adequately differentiate among the impacts of outages on various customer classes.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 2B, Section D3, page 14 and Section E1, page 4 (corrected)

a) Please update Table 1 (Exhibit 2B – Section 1E) if the peak value used as the proxy for number of connected customers was reduced by 25%.

b) Please update Table 1 (Exhibit 2B – Section 1E) if average peak period load was used as the proxy for number of connected customers.

RESPONSE:

a) In order to update Table 1 to adjust the peak value used as the proxy for the number of connected customers, Toronto Hydro would have to develop an entirely new 2015-2019 capital expenditure plan based upon a different mix of assets to be addressed. For these reasons, an adjustment to Table 1 cannot be reasonably produced within the scope of an interrogatory response.

However, Toronto Hydro can confirm that, in any event, the proposed changes to the peak value are unlikely to result in significant changes to the expenditures as contained in Table 1 for the following reasons:

1) Since the peak load associated with each asset would change by the same percentage, the resulting mix of assets is unlikely to change dramatically.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

2) Any marginal changes to the mix of assets recommended for renewal would have limited impact on the capital plan proposed due to Toronto Hydro's paced execution strategy and the need to put forward a mix of capital programs that can be executed.

3) Finally, it should be noted that the BCE results represent only one element of the capital planning process. The full justification for the proposed capital investment programs is detailed in Sections E5 to E8 within the Distribution System Plan (Exhibit 2B).

b) As stated in the response to VECC Interrogatory 28 (c) as part of the EB-2012-0064 application (EB-2012-0064, Tab 6F, Schedule 11-28, page 2), the "average load in the peak period is not available at the individual asset level", and therefore Table 1 cannot be updated using these values.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 18:

Reference(s): Exhibit 2B – Section D3 page 14 and Section 1E page 4

Preamble:

THESL states the peak load is used as a proxy for the number of connected customers as it represents the full number of customers that may have needed power during an outage.

a) Please provide the total number of outages (due to equipment failure) that occurred in the on-peak period, and the total number of outages (due to equipment failure) that occurred off- Peak. Please provide average on-peak outage duration, average off-peak outage duration, and overall average outage duration. Please complete the table provided below.

Line No.	**Description**	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
		(a)	(b)	(c)	(d)	(e)
	Due to Equipment Failure					
1	**Outages during On-Peak**					
2	**Outages during Off-Peak**					
3	**Total Outages (line1 + line2)**					
4	**Percent Outage During On-Peak (line1)/(line3)**					
5	**Percent Outage During Off-Peak (line2)/(line3)**					
6	**Average Duration of Outages On-Peak (Hr)**					

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

7	**Average Duration of Outages Off-Peak (Hr)**					
8	**Average Duration of Outages Overall (Hr)**					

b) Please update Table 1 "Capital Investment by Categories" (Exhibit 2B - Section E1) if the peak value used as proxy for number of connected customers in the FIM was multiplied by the percent of outages that occurred during on-peak in 2013 (Column e line 4 from part a)

RESPONSE:

a) The following table shows data pertaining to sustained interruptions caused by defective equipment failures and includes MEDs. All weekends and statuary holidays were also considered to be Off-Peak (New Years Day, Family Day, Good Friday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, Christmas Day, Boxing Day).

Line No.	Description	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
		(a)	(b)	(c)	(d)	(e)
	Due to Equipment Failure					
1	**Outages during On-Peak**	381	368	335	250	290
2	**Outages during Off-Peak**	348	364	361	317	367
3	**Total Outages (line1 + line2)**	729	732	696	567	657
4	**Percent Outage During On-Peak (line1)/(line3)**	52.3%	50.3%	48.1%	44.1%	44.1%
5	**Percent Outage During Off-Peak (line2)/(line3)**	47.7%	49.7%	51.9%	55.9%	55.9%
6	**Average Duration of Outages On-Peak (Hr)**	3.29	3.98	3.81	4.05	5.09
7	**Average Duration of Outages Off-Peak (Hr)**	4.66	4.22	4.12	4.67	4.70
8	**Average Duration of Outages Overall (Hr)**	3.95	4.10	3.97	4.40	4.87

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

The following table lists the official Peak/Off-Peak times that were in effect throughout the years as per the OEB and were used to produce the graph above.

	2009		2010	2011		2012	2013
Start Date	1-Jan-09	1-Nov-09	1-Jan-10	1-Jan-11	1-May-11	1-Jan-12	1-Jan-13
End Date	31-Oct-09	31-Dec-09	31-Dec-10	30-Apr-11	31-Dec-11	31-Dec-12	31-Dec-13
On Peak	7AM to 10PM	7AM to 9PM	7AM to 9PM	7AM to 9PM	7AM to 7PM	7AM to 7PM	7AM to 7PM
Off Peak	10PM to 7AM	9PM to 7AM	9PM to 7AM	9PM to 7AM	7PM to 7AM	7PM to 7AM	7PM to 7AM

b) Please see the response to Interrogatory 2B-AMPCO-17 part (a), which provides the underlying interactions between the peak load value and long-term and short-term planning processes that are used to produce the underlying results in Table 1. As is the case with the proposed adjustment that was requested with Interrogatory 2B-AMPCO-17 part (a), the adjustments proposed in 2B-AMPCO-18 part (a) also would not change Table 1.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 19:

Reference(s): Exhibit 2B, Section D3 page 14 and Section 1E page 4

Preamble:

THESL states the peak load is used as a proxy for the number of connected customers as it represents the full number of customers that may have needed power during an outage. The Interruption Tracking Information System stores historical information and provides insight into the number of customers affected by an outage event and the duration of each event.

a) Please provide the number of customers that were affected by outages (due to equipment failure) that occurred On-peak and the number of customers affected by outages due to equipment failure that occurred Off-Peak for periods 2009-2014. Please also provide the peak load proxy for number of customer affected by the outages for periods 2009-2014. Table below provided, please complete.

Line No.	Description	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Budget
		(a)	(b)	(c)	(d)	(e)	(f)
	Due to Equipment Failure						
1	Customer affected by Outage On-Peak						
2	Customer affected by Outage Off-Peak						
3	Total Customer affected by Outline (line 1+line 2)						
4	Percent Customer affected by outage On-Peak (line1)/(line 3)						
5	Percent Customer affected by outage Off-Peak (line2)/(line 3)						

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

RESPONSE:

a) The following table is based on the information in the response to 2B-AMPCO-18.

Line No.	Description	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
		(a)	(b)	(c)	(d)	(e)
	Due to Equipment Failure					
1	Customer affected by Outage On-Peak	256,629	253,663	221,487	225,750	208,890
2	Customer affected by Outage Off-Peak	261,910	237,661	213,091	233,387	204,886
3	Total Customer affected by Outage (line1 + line2)	518,539	491,324	434,578	459,137	413,776
4	Percent Customer affected by Outage On-Peak (line1)/(line3)	49.5%	51.6%	51.0%	49.2%	50.5%
5	Percent Customer affected by Outage Off-Peak (line2)/(line3)	50.5%	48.4%	49.0%	50.8%	49.5%

The Interruption Tracking Information System reports customer counts that are impacted by an outage and does not contain the asset level information required to produce the requested peak load proxy. Please refer to response to Interrogatory 2B-AMPCO-20 for more details.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 2B, Section D3, page 14 and page 19

Preamble:

The Interruption Tracking Information System stores historical information and provides insight into the number of customers affected by an outage event and the duration of each event.

a) Given the Interruption Tracking Information System (IT IS) provided insight into the actual number of customers affected by an outage event, why does THESL use the peak load as a proxy for the number of connected customers as an input for the FIM? Please explain.

RESPONSE:

a) The Interruption Tracking Information System ("ITIS") contains information with respect to customers impacted by historical outage events. ITIS does not contain asset level information, which is required by the Feeder Investment Model to produce its outputs. In addition, ITIS only reports customer counts that are impacted by an outage, regardless of customer class or whether it is a bulk-metered multi-residential account, as per the reporting requirements specified in the Board's RRR document. The Feeder Investment Model requires this more granular customer information to accurately quantify the criticality of a customer outage.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 21:

Reference(s): Exhibit 2A, Tab 10, Schedule 2 Page 11 Table 2

Preamble:

Table 2 provides the percentage contribution of Defective Equipment to SAIFI & SAIDI.

a) Please provide a further breakdown of the causes of Defective Equipment that make up the percentages shown in Table 2.

RESPONSE:

a) Please see table below:

Equipment	Contribution % to SAIFI	Contribution % to SAIDI
Underground Cables	39.3%	39.5%
Poles and Pole Hardware	21.1%	19.5%
Switches	16.4%	11.4%
Overhead Conductors	7.7%	6.9%
Others	6.6%	6.4%
Transformers	5.0%	7.7%
Stations Equipment	3.8%	8.6%

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 22:

Reference(s): Exhibit 2A, Tab 10, Schedule 2

a) Please complete the following table excluding loss of supply.

	2009	2010	2011	2012	2013	2014
Number of Interruptions						
Number of Customers Interrupted						
Customer Hours Interrupted						

b) Please provide THESL's SAIDI and SAIFI targets for the 2015 to 2019 period.

RESPONSE:

a) Please see table below. Please note that Toronto Hydro is unable to provide a 2014 year-end forecast as it is unable to forecast the impact of MEDs. Please also refer to the response to Interrogatory 2A-EP-8.

	2009	2010	2011	2012	2013	2014F*
Number of Interruptions	1,885	2,153	1,915	1,669	2,352	N/A
Number of Customers Interrupted	1,176,735	1,070,057	1,045,478	1,048,668	1,726,330	N/A
Customer Hours Interrupted	1,900,573	828,500	968,876	1,039,886	12,885,642	N/A

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

b) Please refer to the response to Interrogatory 2B-OEB-33 for the SAIDI and SAIFI projections for the proposed CIR scenario. Please note that these projections are not targets for the CIR period.