

Unapproved Minutes from WPM 2001

To: Working Group on System Design
CC: Dan Ward, Dan Sabin
From: Cheri Warren
Date: 2/31/2001
Re: Minutes from the Working Group on System Design from the 2001 Winter Power Meeting in Columbus, OH

35+ members and guests attended the meeting that began at 8 AM.

We request that our meetings be listed in the program as follows:

1. The TF groups meet concurrently with the WG on System Design as outlined below. Please list them in the program as TF as well as WG on System Design and schedule them in the same room.
 - a) TF on Reporting Practices from 8 to 9 - Chair Dan Pearson
 - b) TF on System Design from a Reliability Perspective from 9 to 10 - Chair Jim Bouford
 - c) TF on Reliability Indices from 10 to 11 - Chair Cheri Warren
 - d) WG on System Design from 8 to 12 – Chair Cheri Warren
2. We need a BIGGER room!

The minutes from the SPM 00 were approved.

TF on Outage Reporting Practices – Chair Dan Pearson - PGE

This group met from 8:15 to 8:20. Dan was unable to attend this meeting due to the Californian power crisis. The TF paper will be submitted by the end of February and hopefully will be presented at the SPM in Vancouver.

TF for Reliability Indices P1366 - Chair Cheri Warren - Navigant Consulting

The meeting was full of great discussion and many good points were made. The main debate surrounded the “Major Event” definition with four broad topics:

1. Original definition
2. 3σ on an annual or multiple year basis
3. NWS, 10% of an operating region or company...
4. # of Events per # of Customers/Event per CMI/event

During the last six months, the group performed an informal members survey with the following four questions:

1. How many times have you seen 10% of your "total company customers served" out of service during a storm?
2. How many times have you seen 10% of the "customers served in an operating region" out of service during a storm?
3. What is your storm definition?
4. What is your definition of a customer?

Responses to Q1:

Texas/New Mexico	In 8 years, I can only recall one time (Major wind storm of Jan 16, 1996... 80+ poles down) when we might have had 10% (29K) of our customers out of service (of course we didn't have a formal outage recording system back then).
California	1995 - 3 events 1996 - 2 events 1997 - 0 events 1998 - 1 event 1999 - 0 events 2000 - 0 events
Hawaii	Twice in the last 50 years...1982 and 1992, both following hurricanes.
Illinois	No
New York	A major storm is at least 10% of a regions customer base interrupted or customers interrupted in excess of 24 hours.
New Jersey	Extremely rare if ever. No instances of recollection. Approximately 1 out of every 2-3 years PS has a major storm of this magnitude.
Arizona	2
Massachusetts	Over the past eight years, 1993 - 2000 5 events > 10% of total custs. "at any one time"
Wisconsin	Twice in the last 10 years, both times in 1998.

Responses to Q2:

Texas/New Mexico	2. Same as above (one region, the El Paso Region, was hardest hit)
California	2. We do not track this item.
Hawaii	2. Same since our total company customers are on the island of Oahu and our operating region is also the island of Oahu.
Illinois	2. no
New York	A customer is on active electric meter.
New Jersey	Extremely rare if ever. No instances of recollection.
	1 or 2 times per year on average. Divisions have about 500 K
	customers each.
Arizona	3
Massachusetts	24 events > 10% of custs in one or more operating areas "at any one time"
	2 events of severe weather, with major consequences, but, with less than 10% of customers in any operating area affected "at any one time"
Wisconsin	Not readily available. If I have time before the meeting, I will get the answer.

Responses to Q3

Texas/New Mexico	3. We define a major event as any natural occurrence.... We typically use the "exceeds the design criteria" approach.... If we sustain an intense thunderstorm (not unusual) with which the national weather service records a micro-burst of wind above 60mph (our design standard) we classify the entire storm as a major event.... The 10% customers affected rule rarely applies.
California	A storm/major event is defined as when > 10% of the customers in the system have experienced a sustained outage > within a 48 hour period.
Hawaii	3. Hurricanes (wind speeds in excess of 70 mph) are considered major storms.
Illinois	3. ICC nor CILCO has one- ICC doesn't like the idea.
New York	I am not sure how many times the system has had 10% interrupted. I think the ice storm and labor day storm in 1998 may have hit that mark.
New Jersey	Under New Jersey's new Interim Electric Distribution Service Reliability And Quality Standards, a "Major event" is defined amongst other things as "A sustained interruption of electric service resulting from conditions beyond the control of the EDC, which may include, but is not limited to, thunderstorms, tornadoes, hurricanes, heat waves or snow and ice storms, which affect at least 10 percent of the customers in an operating area." For us with about 2 million customer statewide and 4 operating areas, that works out to roughly 50,000 customers per operating area. Previously, we would not include events in our reliability reporting where 100,000 customers or more were affected by inclement weather. Operating area mergers over the years has impacted the count of customers per area. The NJ BPU defines a major storm or event as a utility having 10% of their total customers out of service. PSE&G classifies a storm or event as having 30K to 50K customers out of service. This means multiple feeders or atleast a whole large substsation as a threshold.
Arizona	No Definition
Massachusetts	Weather event affecting >10% of customers at any one time in any operating area, any storm costing more than \$1,000,000 to restore all customers, any severe weather event with attendant major consequences (The last category is obviously used with discretion, and has much greater chance for regulatory review. An example of such a storm was the severe wind storm of December 17-18 that impacted every portion of our service territory with sustained winds > 70 mph, and gusts > 75 mph. At no time did we have 10% of the customers out of service in any area)
Wisconsin	A Major Storm is defined as one affecting more than 10,000 customers over a wide spread area due to severe weather conditions within a single day.

Responses to Q4

Texas/New Mexico	4. We make no distinction between customer classes, and each meter represents a customer... (primary metered customers are one customer... even if its a primary metered apartment complex).
California	A customer is defined as being an open account served by the electric distribution system in our customer billing database.
Hawaii	4. A metered account is considered a customer whether a single family residence or a high-rise condominium with a single meter.
Illinois	A Meter
New York	For a region, we usually have 4 or 5 events per year in which a region has 10% of its customer base affected.
New Jersey	A customer to us would equate to any revenue meter/account on record. In general, every meter is a customer although some customers may have multiple meters either on premises or spread across other sites. We would not include end-users who might be a tenant of a facility and provided energy through a single meter aggregating the usage of all of the tenants, only the account name of record. A customer is a bill paying entity. It can be a large industrial customer or a single metered service to an apartment. The meter is the key. does not count unmetered services as a customer presently.
Arizona	Active Billing Meters
Massachusetts	One retail bill, one customer (not including street light accounts)
	Note: The 10% at any one time criteria is more severe than the 10% total during an event that many Companies have. I would expect that the number of events that qualify for exclusion would at least double. I have no good way to check that theory out.
Wisconsin	For reliability reporting purposes, a customer is defined as a separate electrical service point. Customers may be residential, commercial, industrial, or municipal. In Addition, we have what is called "An Extraordinary Event" definition. These are removed from our Reliability Indices for reporting purposes.
	* An Extraordinary Event is a significant event that occurs and is declared when one of the following conditions are met: severe weather conditions that result in 100,000 or more customer interruptions within a single day, events of sufficient intensity to give rise to a state of emergency declaration by the local, state, or federal government, or events that are the direct result of failures in the Independent System Operator's controlled bulk power market or other transmission facilities not owned by the distribution utility.

Three presentations were made regarding storm/major event definitions. Thanks to the three presenters: Dennis Hansen in absentia (dennis.hansen@pacificorp.com), Charlie Williams (CHARLES.WILLIAMS@pgnmail.com), and Jim Bouford (james.bouford@us.ngrid.com).

A summary of comments on the original definition:

- Operating region/company needs to be better specified and if we use operating region, then a definition for operating regions needs to be added.
- The definition still need to be tightened up.

Charlie's presentation focused on a particularly severe lightning event that occurred in the sun coast area. One area got 3 times the normal lightning level, yet was not excluded from the data as an abnormal event. Bottom Line -- present definitions are not good enough. Presentation may be sent later.

Dennis Hansen was unable to attend, but kindly provided slides for the meeting describing the ScottishPower method for determining storm days. Please see attached. They use 3σ for a one year period. While one year is definitely too short a view because that approach guarantees that major events will happen every year, there may be merit in reviewing 5-7 years of data using this criterion. Jim Burke argued that using 3σ on a longer basis was similar to the methodology presented by Jim Bouford and that it is an established method.

Roy Billinton pointed out that the 3σ concept only works for normal distributions and that interruption data is anything but normal!

Jim Bouford presented a method for determining storms days using 7 years of actual data. He created plots:

- 3D # events by # CI/Event by CMI/Event and
- 2D CMI/Day by # events per day yearly and for all years

Abnormal events were easily identifiable when viewed on the plots describe above. Jim stressed that we should consider normal and abnormal events and then use the data accordingly. It would be reasonable for regulators to require significant detail (like hourly reports) during abnormal events.

Mike Sheehan from Puget Sound Energy volunteered that their current definitions are:

- Storm - 5% of customers out of service
- Major Event - 25% of customers out of service and associated costs are capitalized.

Puget believes that SAIFI etc. are the wrong metrics and that the customers must be considered. They are using customer complaints as their metric. There was additional discussion about customer satisfaction surveys.

Charlie Williams volunteered to review their 30 years of historical interruption information to help review the arguments.

A suggestion was made to add an annex on current state reporting practices.

Jerry Murray from the Oregon PUC mentioned that Oregon would like to see a "normal" and "major" classification. In the "normal case", it is business as usual with all the prescribed reporting. When a "major" event occurs, they would like hourly reporting. He is aware and

accepts that not all records are kept as accurately as during normal operations, but that he knows the utilities are doing the best they can.

Roy Billinton from CEA also spoke on the CEA definitions and has agreed to give a short presentation at our next meeting. CEA records *Adverse Weather* as a code. They also keep track of *Loss of Supply* and *Human Error*. Roy has volunteered to be a liaison between CEA and our group. Thanks to Roy! CEA produces two reports (1) with all data and (2) with sensitive data removed.

The group decided that one of the main purposes for the guide was to provide a uniform reporting approach and as such, the definitions require more specificity. The next revision (D6) will attempt to strengthen the definitions to provide an IEEE reporting methodology. Two key concepts to be added to the Guide are Normal and Abnormal Events.

The group (specifically: Charlie Williams, Jim Bouford, Val Werner, Tom Kulas and all the other silent members!!) also decided to review their own data and provide feedback to Cheri Warren on the number of events per year on an operating and company total basis for 5% to 10% of customers interrupted as described by the tables below.

Operating Region Basis						
	5%	6%	7%	8%	9%	10%
1990						
1991						
1992						
1993						
1994						
1995						
1996						
1997						
1998						
1999						
2000						
Total Customers Served						
	5%	6%	7%	8%	9%	10%
1990						
1991						
1992						
1993						
1994						
1995						
1996						
1997						
1998						
1999						
2000						

After the "Major Event" discussion, the group briefly discussed customer counts and agreed that the definition can cause issues. We updated the definition to be sure meters and customers agreed.

Charlie Williams will ask the T&D Committee to pass the guide to RevCom to change IEEE1366-1998 from a Trial Use Guide to a Guide.

TF on System Design from a Reliability Perspective - Chair Jim Bouford NEES

This task force met for 30 minutes. The intent is to create a document on design practices that is intended for new distribution engineers. It will provide a method to provide the collected wisdom of this group to those who haven't had time to collect it. The following people have volunteered to help Jim:

Dave Gilmer	Cheri Warren	Mike Sheehan	Jim Burke
Charlie Williams	Manuel Gonzalez	John McDaniel	Tom Kulas
Dan Ward	Dave Blew	Rodney Robinson	Charles Perry

Jim put together an outline for the paper as shown below:

Distribution Design Options for Improving Reliability

- I. Determining the Cause of Interruptions
 - Interruptions vs. Outages
 - Why identifying causes is important
 - You're only as good as your data
 - Receiving good data
 - Verifying the accuracy of the data
 - Determining what the "unknown" causes really are

- II. Reduce the Number of interruption events
 - Tree Caused
 - Trimming programs
 - Effectiveness
 - Technical aspects
 - Productivity enhancing programs
 - Construction options
 - Tree wire
 - Spacer cable
 - Aerial cable
 - Animal Caused
 - Birds
 - Squirrels
 - Snakes
 - Other
 - Lightning Caused
 - Arrester application

Construction options
Defective equipment/material Caused
Human error Caused
Underground vs. Overhead construction

III. Reduce the Number of Customers interrupted per Event
Feeder Segmentation
 Recloser/fuse application
 Single phase recloser application
K type vs. T type Fuses
CSP vs. Conventional transformers

IV. Reduce the Length of Restoration Time per Event
Practical Application of Feeder ties
Fault Locators
Distribution Automation

The group is hoping to have a draft by the next meeting and will meet for one hour in Vancouver. Jim will contact the volunteers prior to the meeting.

Round Table of System Design Issues

Dick Hensel (rwhensel@cmsenergy.com) provided an update on the NESC code which will be published in August. There will be no new wind maps until 2002 or later. They added calculations for 60 ft. poles. Please contact Dick for more information.

Val Werner (val.werner@wepeco.com) related that several sources have been misquoting P1366 relative to momentaries.

Jerry Murray (jerry.murray@state.or.us) discussed joint use issues in Oregon. With the insurgence of telecom/cable providers, this is becoming an issue. There have been cases where 9 utilities have been attached to a single pole. Now the poles need to be upgraded at the rate payers expense.

New Business

None.