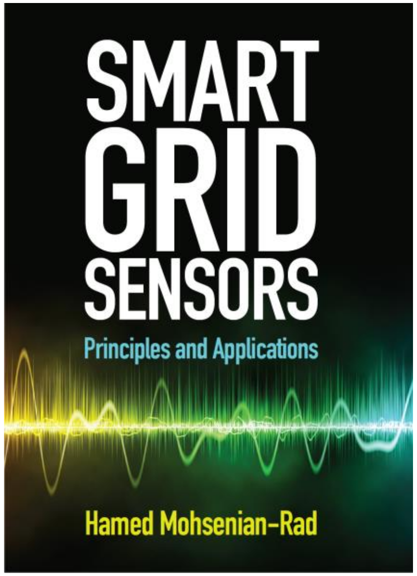
Chapter 4: Waveform & Power Quality Measurements and Their Applications



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Overview

- So far, most of the discussions in this course have been based on the explicit or implicit assumption that the AC voltage and current signals are *purely sinusoidal*. However, this assumption may *not* hold in practice.

- In practice, both voltage and particularly current may include *distortions* and take *non-sinusoidal* waveforms.

- The instrument to measure voltage and current waveforms is called the *waveform sensor*, which is a broad term for a wide range of sensor devices that have the capability to report the voltage or current waveform.

- Waveform sensors operate at very high sampling rates, such as at 256 samples per cycle, i.e., 15,360 samples per second [199].

- **Note**: These sensors often report the raw samples that they capture of the voltage or current waveform; thus, the *reporting rate* is the *same*.

Overview

• This reporting/sampling rate is much higher than those of practically every other power system sensor, including PMUs in Chapter 3, e.g., compare it with 24 samples per cycle for a 10 fps PMU [133].

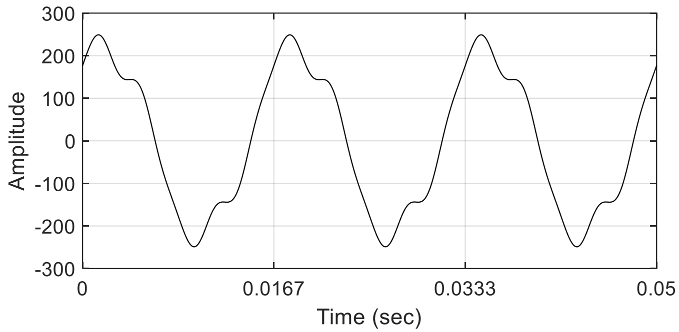
• At such high sampling rate, a waveform sensor generates 3,981,312,000 samples per day from a single three-phase current signal.

• This is a *huge amount of data* to report.

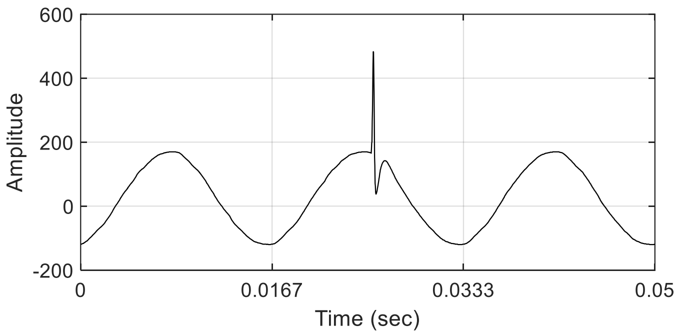
• In practice, most samples are *discarded* shortly after they are collected and as soon as they go through a light-weight analysis inside the sensor.

Overview

- In general, the analysis of waveform measurements can focus on
  - *Steady-state Distortion*



  - *Transient Distortion*



- Thus, waveform sensors may provide measurements that are *continuous* (for steady-state analysis) or *event-triggered* (for transient analysis).

Overview

- A waveform sensor may *continuously report* of certain metrics for *steady-state* waveform distortion and power quality (see Section 4.1).

- This type of sensors are sometimes referred to as power quality meters.
    - Or PQ meters.

- PQ meters may have other reporting features in addition to examining steady-state distortion in waveform measurements.

- For example, they also may analyze *RMS voltage variations*, *frequency variations*, *voltage unbalance*, and *service interruptions*.

Overview

- A waveform sensor may also provide an *event-triggered* reporting of the voltage or current waveforms (see Sections 4.2–4.4).
    - This is meant to capture *transient* waveform distortions.
- Most PQ meters gave this type of event-triggered capturing capability.
- Also true for some other devices, such as *Digital Fault Recorders* (DFRs).

Overview

- Waveform sensors may also be called *Point-on-Wave* (PoW) sensors.

- There are also other types of waveform sensors that have emerged recently, such as the sensor devices to measure:

    - *Synchronized Harmonic Phasors* (see Section 4.5)

    - *Synchronized Waveforms* (see Section 4.6)

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4.1. Steady-State Waveform Distortion

- *Steady-state* waveform distortions are often due to nonlinear loads.

- A load is *nonlinear* if its impedance changes with the applied voltage.

- The current that is drawn by a nonlinear load becomes non-sinusoidal, even if the applied voltage is sinusoidal. The nonlinearity can be due to:

  - Static power converters, including AC to DC converters.

  - Variable frequency drives (VFDs)

  - Discharge lighting such as fluorescent lamps

  - ...

4.1. Steady-State Waveform Distortion

- Static power converters, such as the inverters for *distributed energy resources* (DERs), such as PVs and batteries, may similarly contribute to current and voltage waveform distortions [200].

- Even though *individual* inverters are often mandated to comply with harmonic emission limits set by industry standards, the *cumulative effects* of the harmonics that are injected by a large number of inverters may still cause considerable harmonic distortions in the power system that need to be accurately identified [201].

- Accordingly, it is important to monitor *steady-state* waveform distortions, such as *harmonics*, *inter-harmonics*, and *notching*.

  - As we will discuss next.

4.1. Steady-State Waveform Distortion

4.1.1. Measuring Harmonics

- A *non-sinusoidal* signal $x(t)$ can be expressed in a Fourier series as:

$$x(t) = \sum_{h=1}^{\infty} \sqrt{2} X_h \cos(h\omega t + \phi_h).$$

- The first term, corresponding to $h = 1$, is the *fundamental* component.

- The other terms are the *harmonic* components.

- They are sinusoidal waves at harmonic angular frequencies 2ω,3ω,4ω, etc.

- Collectively, the harmonic waves create the *distortions* in the signal.

4.1. Steady-State Waveform Distortion

- **Note**: A non-sinusoidal but *symmetrically distorted* signal comprises only the *odd-numbered components*; see *Exercise 4.3*.

- In practice, waveform sensors use DFT to obtain the parameters of the Fourier series on the previous slide, i.e., to obtain X_h and ϕ_h for each h.

- The RMS value of the non-sinusoidal signal on Slide 11 is obtained as

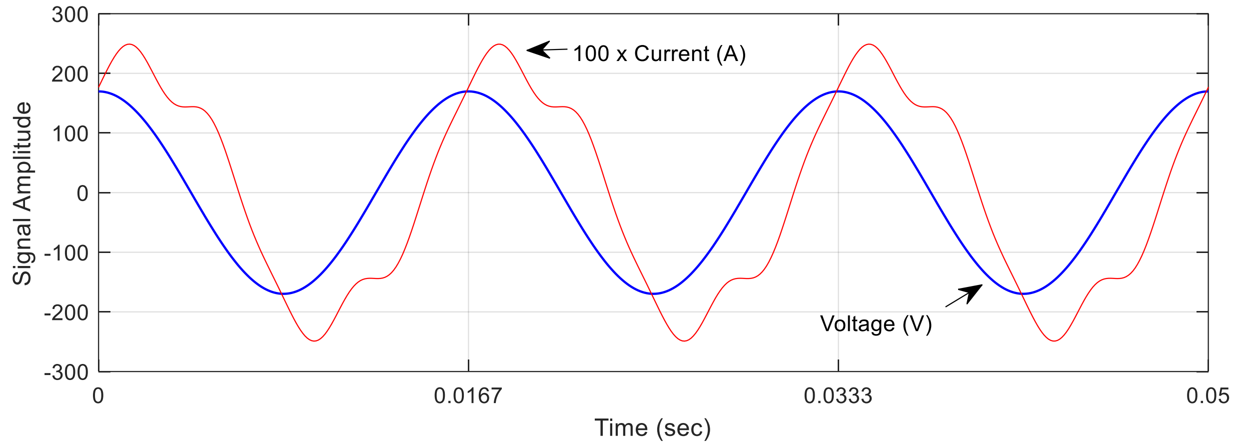
$$X_{\mathrm{rms}} = \sqrt{\sum_{h=1}^{\infty} X_h^2}.$$

- If all harmonic components are zero, then $X_{\mathrm{rms}} = X_1$.

4.1. Steady-State Waveform Distortion

• **Example 4.1**: Consider the voltage and current measurements for the motor load in Example 3.1 in Chapter 3. In an ideal scenario, the voltage and current signals are purely sinusoidal, as we saw in Example 3.1.

However, in practice, the signals may look more like the following:



Here, the current waveform $i(t)$ is *not sinusoidal*:

4.1. Steady-State Waveform Distortion

- **Example 4.1 (Cont.)**: The current signal has the following form:

$$\begin{aligned} i(t) = 1.60\sqrt{2}\cos(\omega t - 0.7532) \\ + 0.27\sqrt{2}\cos(3\omega t - 0.4323) \\ + 0.15\sqrt{2}\cos(5\omega t + 3.3058). \end{aligned}$$

It includes the 3rd and the 5th harmonics. Its RMS value is obtained as

$$I_{\text{rms}} = \sqrt{1.60^2 + 0.27^2 + 0.15^2} = 1.63 \text{ A}.$$

The above RMS value is *equal* to the RMS value in Example 3.1.

A sensor that measures only the RMS value *cannot distinguish* the non-sinusoidal signal in this example and the sinusoidal signal in Example 3.1.

4.1. Steady-State Waveform Distortion

- PQ meters may provide *weekly summery reports* of the harmonic measurements based on standard power quality requirements, such as based on the EN 50160 standard on voltage characteristics [202].

- These reports often distinguish:
  - *even* harmonics,
  - *odd* harmonics that are *multiples of three* (*triplen* harmonics),
  - *odd* harmonics that are *not* multiples of three (non-triplen harmonics).

- The reason for the last two distinctions is discussed in *Exercise 4.8*.

- Also recall that *even* harmonics are *zero* under *symmetrical distortions*.

4.1. Steady-State Waveform Distortion

- It is common to use a single quantity, the *total harmonic distortion* (THD), as a measure of the magnitude of harmonic distortion.

- THD is defined as

$$\mathrm{THD} = \sqrt{\sum_{h=2}^{\infty} \left(\frac{X_h}{X_1} \right)^2} \times 100\%.$$

- THD is often calculated up to the 40th or 50th harmonic.

- **Note**: We can show that:

$$X_{\mathrm{rms}} = X_1 \sqrt{1 + \mathrm{THD}^2}.$$

4.1. Steady-State Waveform Distortion

- The harmonic distortion in *current* may be presented also in terms of another similar index, namely, the *total demand distortion* (TDD):

$$\text{TDD} = \sqrt{\sum_{h=2}^{\infty} \left(\frac{I_h}{I_{1,\,\max}} \right)^2} \times 100\%,$$

where $I_{1,\max}$ is the average monthly peak of the RMS current over the past 12 months. Hence, $I_{1,\max}$ is practically a *normalization constant*.

while THD can fluctuate with changes in the mix of harmonic versus non-harmonic loads, TDD is normalized such that it does not change due to changes in non-harmonic loads.

4.1. Steady-State Waveform Distortion

- Another index to represent harmonic distortion in *current* waveform measurements is the *crest factor* (CF), which is defined as

$$\mathrm{CF} = \frac{I_{\mathrm{peak}}}{I_{\mathrm{rms}}}.$$

- It is the absolute peak of the *instantaneous* current signal.

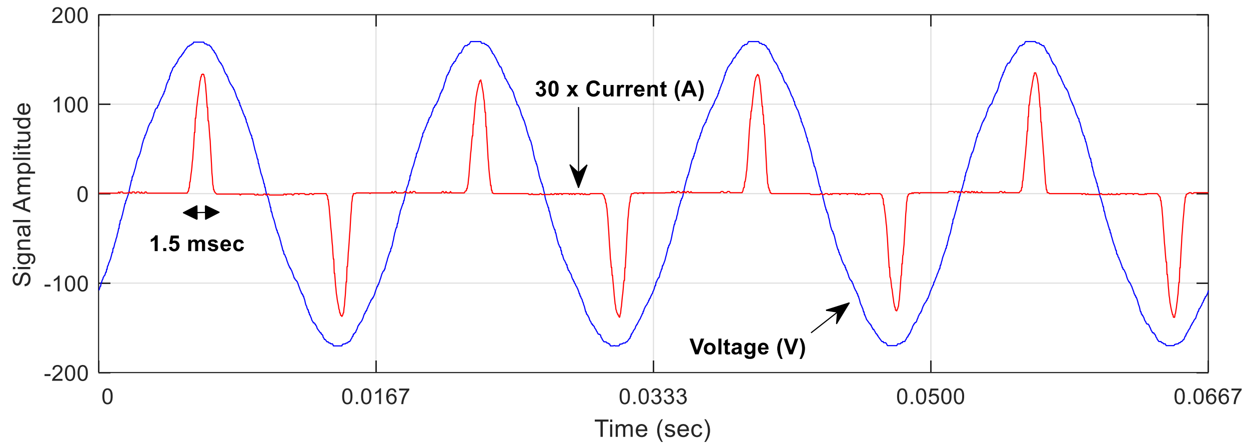
- The peak value and the RMS value are taken from the *same* cycles.

- CF measures distortion at the moment that the maximum current.

- Q: What is the CF for a purely sinusoidal current waveform.

4.1. Steady-State Waveform Distortion

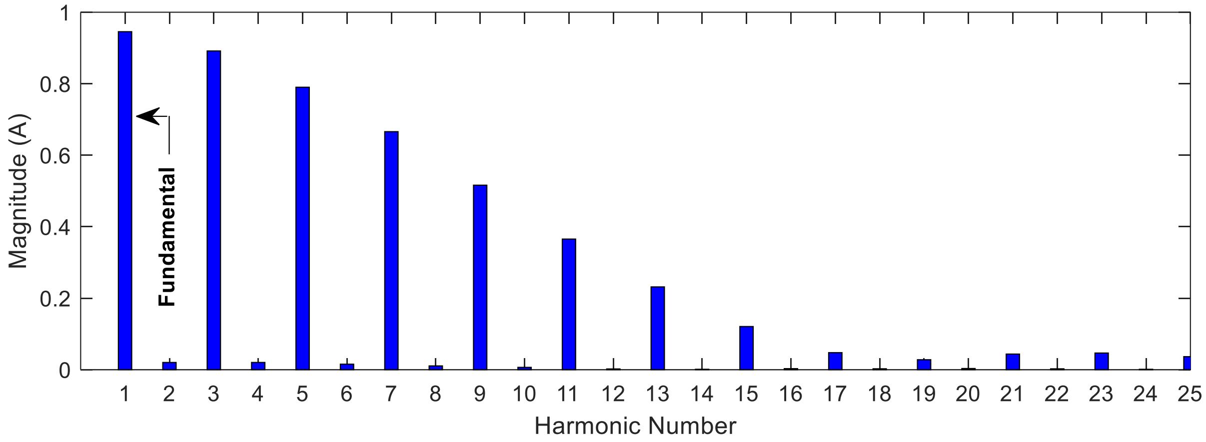
- **Example 4.2**: The voltage and current measurements for a single-phase power electronics load are shown below:



The current waveform is highly distorted, because current is drawn only during a small 1.5 msec time window in each half cycle.

4.1. Steady-State Waveform Distortion

- **Example 4.2 (Cont.)**: The harmonic spectrum for current waveform is shown below up to the 25th harmonic.



- CF is 3.4635 and THD is 161.8%. The current signal is highly distorted.

4.1. Steady-State Waveform Distortion

• **Note**: Most indices for harmonic analysis, such as THD, TDD, and CF, do *not* account for the *phase angles* of the harmonic components.

• One alternative index is the *phasor harmonic index* (PHI) [204]:

$$\mathrm{PHI} = \left(\sum_{h=1}^{\infty} X_h |\cos(\phi_h - \phi_1)| \right) \Big/ \left(\sum_{h=1}^{\infty} X_h \right).$$

• If all harmonic components are in-phase with the fundamental component, then PHI is 1; otherwise, it is a number between 0 and 1.

• PHI gives higher weight to phase angle differences corresponding to the harmonic components that have higher magnitudes.

• The PHI in Example 4.1 is obtained as 0.964.

4.1.2. Measuring Inter-Harmonics

- In practice, distortions are often *not* exactly identical across cycles.

- Therefore, the waveform may include components that are not integer multiples of the fundamental frequency.

- These components are referred to as *inter-harmonics*.

- Inter-harmonics cannot be expressed by the formulation on Slide 12.

    - We need to revise the formulation (next slide).

4.1. Steady-State Waveform Distortion

- Let C denote the number of cycles of the measured signal $x(t)$ that are considered in calculating the harmonic and inter-harmonic components.

- The signal can be expressed as

$$x(t) = \sum_{n=1}^{\infty} \sqrt{2} X_n \cos((n/C)\omega t + \phi_n).$$

- The terms where n is a multiple of C correspond to harmonics.

- The terms where n is *not* a multiple of C correspond to inter-harmonics.

- **Note**: $n = C$ corresponds to the fundamental component (not $n = 1$).

4.1. Steady-State Waveform Distortion

- Inter-harmonics are *not* periodic at the fundamental frequency.

- They can be seen as a measure of the *non-periodicity* of the waveform.

- On Slide 12, we measure one cycle and assume that it is repeated in all other cycles.

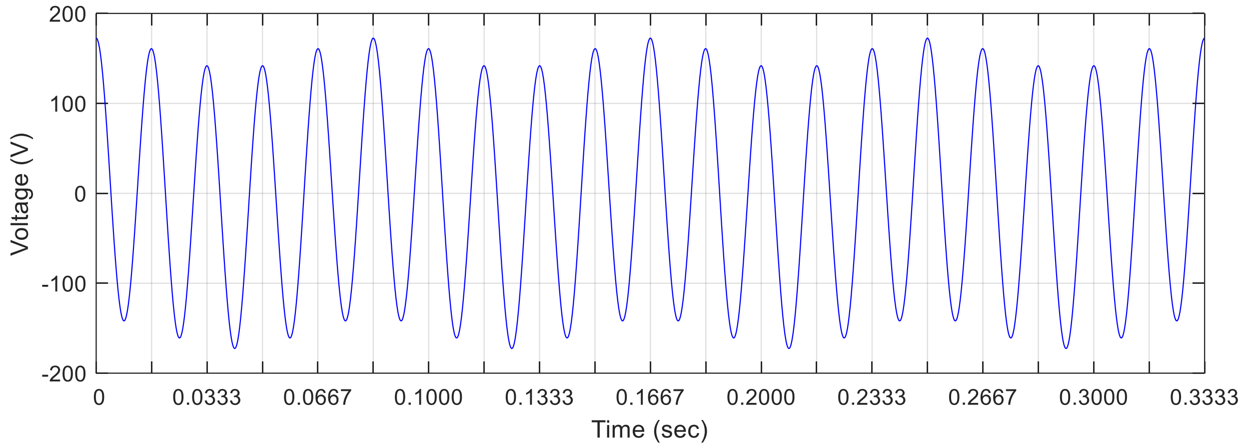
$$x(t) = \sum_{h=1}^{\infty} \sqrt{2} X_h \cos(\underline{h}\omega t + \phi_h).$$

- On Slide 24, we measure a window of C cycles and assume that the entire such window is repeated.

$$x(t) = \sum_{n=1}^{\infty} \sqrt{2} X_n \cos(\underline{(n/C)}\omega t + \phi_n).$$

4.1. Steady-State Waveform Distortion

- **Example 4.3**: Consider the following voltage waveform:



It can be expressed by the following formulation:

$$v(t) = 110\sqrt{2}\cos(\omega t) + 12\sqrt{2}\cos((1/5)\omega t).$$

A total of $C = 20$ cycles are captured in this figure.

4.1. Steady-State Waveform Distortion

- **Example 4.3 (Cont.)**: The inter-harmonic spectrum of $v(t)$ has two bins.

  - One corresponds to the fundamental component

    At 60 Hz, i.e., $n = 20$, with magnitude $110\sqrt{2}$

  - One corresponds to the inter-harmonic component

    At 12 Hz, i.e., $n = 4$, with magnitude $12\sqrt{2}$.

Q: Why?

$$v(t) = 110\sqrt{2}\cos(\omega t) + 12\sqrt{2}\cos((1/5)\omega t).$$

$C = 20$ and $C/n = 1/5$

4.1. Steady-State Waveform Distortion

- Inter-harmonics cause variations in the per-cycle RMS value.

- This can cause *light flicker*.

- PQ meters may provide inter-harmonic measurement summary reports in comparison with the limits on inter-harmonic magnitudes to prevent flicker, based on the IEEE 519-2014 or IEC 61000-2-2 standards [205, 206].

4.1. Steady-State Waveform Distortion

- Inter-harmonics can be caused by sources such as *arcing loads*, *certain induction motors*, *variable load drives*, and *power electronics devices*.

- They can also be due to the presence of power-line communications (PLC) carriers; assuming that PLC carriers are present in the system.

  - To learn more about PLC, see Section 6.5 in Chapter 6.

  - For example, if a PLC-based smart meter communications system operates at 555 Hz and 585 Hz, then PLC carriers appear *between*

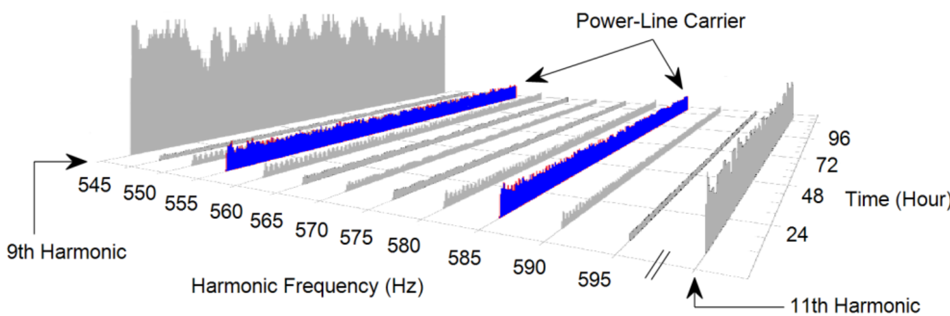
    - the $\lfloor 555/60 \rfloor$ = 9th harmonics

      and

    - the $\lceil 585/60 \rceil$ = 10th harmonics.

4.1. Steady-State Waveform Distortion

- A real-world example is shown below:



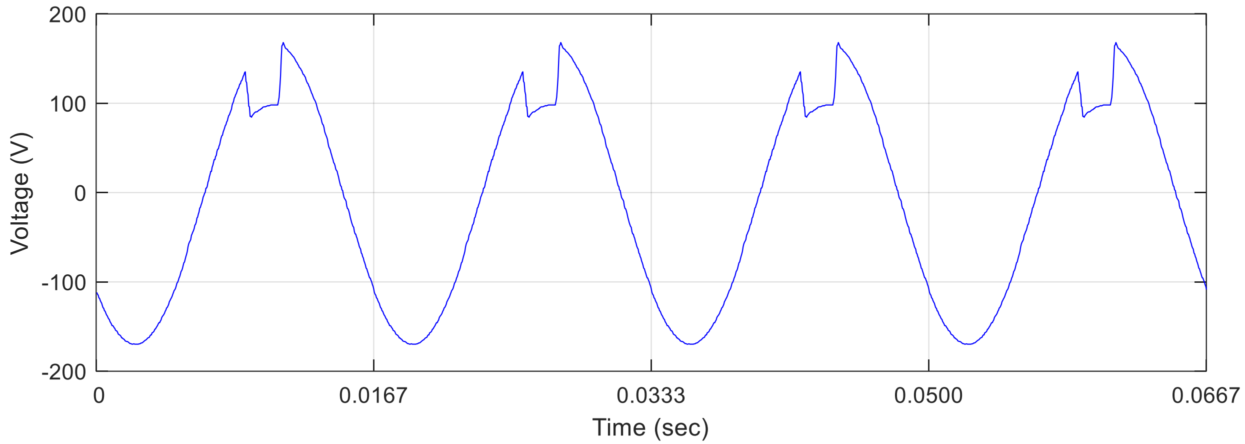
- The inter-harmonics that are caused by PLC are shown in blue.

- they are much lower in amplitude than the 9th or 11th harmonics but higher than any inter-harmonics between these two harmonics.

4.1. Steady-State Waveform Distortion

4.1.3. Measuring Notching

• Voltage notching is a periodic waveform distortion:



• It occurs due to normal operation of certain power electronics devices.

• During the notching period, there is a momentary short-circuit between two phases, thus creating a notch shape in the voltage waveform. The amount of voltage reduction depends on the system impedance.

4.1. Steady-State Waveform Distortion

- If the notch is identical from cycle to cycle, then it creates *harmonics*.

- Otherwise, it also creates inter-harmonics.

- Thus, in principle, voltage notching can be analyzed just like any other steady-state distortion, by analyzing harmonics and inter-harmonics.

  - This analysis would be in frequency-domain.

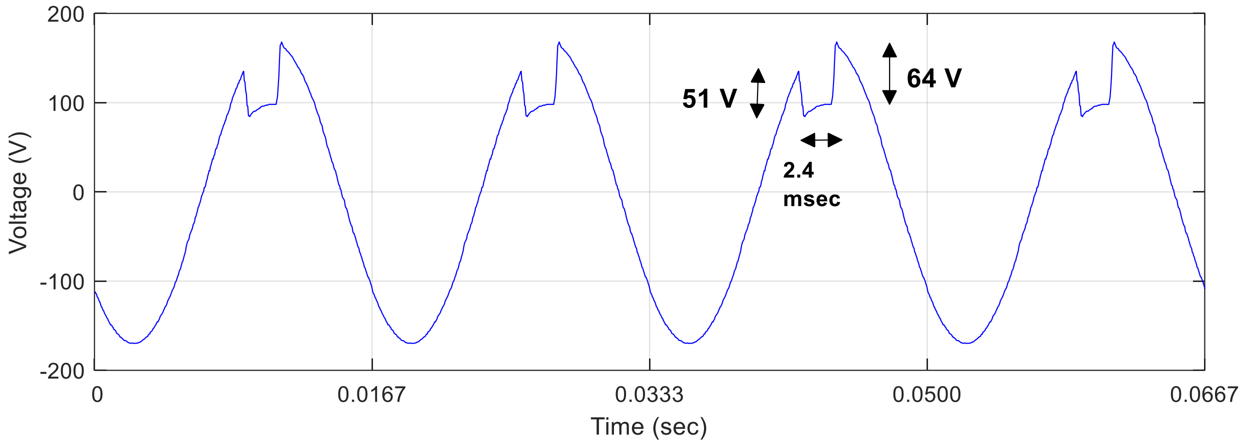
- However, in practice, given the specific and simple shape of notching in *time-domain*, it is easier to quantify it from the raw waveform data.

4.1. Steady-State Waveform Distortion

- This is done by analyzing the following four parameters:
  - *Notch Depth*: the average depth of the notch, compared to the theoretical sinusoidal waveform at fundamental frequency.
  - *Notch Width*: the time duration of the notch.
  - *Notch Area*: the product of the notch depth and the notch width, i.e., the area of the missing piece of the sinusoidal waveform.
  - *Notch Position*: where the notch occurs on the sinusoidal waveform.

4.1. Steady-State Waveform Distortion

- **Example 4.4**: Again consider the voltage measurements on Slide 31:



- The notch depth is approximately calculated as

$$(51 + 64) \,/\, 2 \;=\; 57.5\, V$$

4.1. Steady-State Waveform Distortion

- **Example 4.4 (Cont.)**: The notch width is 2.4 msec = 2400 microseconds.

- Therefore, the notch area is

$$57.5 \times 2400 = 138{,}000 \text{ volt−microsecond.}$$

- According to the IEEE 519-2014 Standard, the notch depth and notch area should be limited to 20% and 22,800 volt-microsecond, respectively, assuming a 480 V system. For a 120 V signal, the limit on notch area is adjusted to $(120/480) \times 22{,}800$ = 5700 volt-microsecond.

- This notch exceeds the limits for both notch depth and notch area.

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4.2. Event-Triggered Waveform Capture

- The previous section focused on *steady-state* waveform distortions.

- In this section, we examine *momentary* waveform distortions.

  - These are the "waveform events".

- Given their very high sampling rate, waveform sensors generate a huge amount of data in a relatively short amount of time.

- Therefore, it is practically impossible, and for the most part unnecessary, to store and report all collected data.

- Instead, the waveform data is *captured* only if the signal waveform is somewhat *unusual* and thus worthy of further examination.

4.2. Event-Triggered Waveform Capture

• An event-triggered waveform capture may is a *waveform snapshot*.

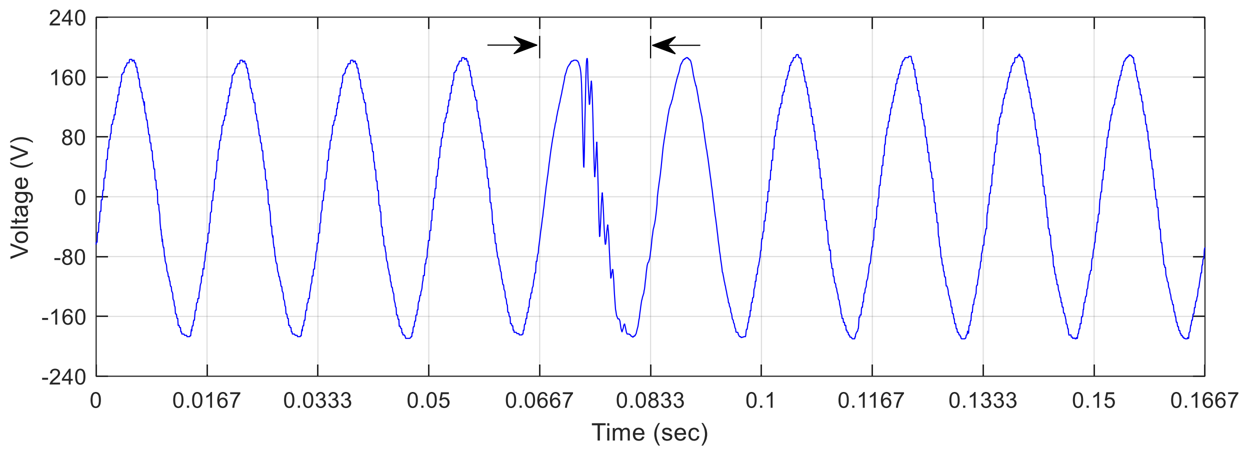
Capturing Events in Waveform Measurements

• Once an event is detected, i.e., we notice something unusual in the waveform, the sensor stores the waveform data over several cycles:

- starting from C_{before} cycles *before* the event
- ending by C_{after} cycles *after* the event

• Parameters C_{before} and C_{after} can be adjusted.

- **Example 4.5**: Consider the voltage measurement across 10 cycles:

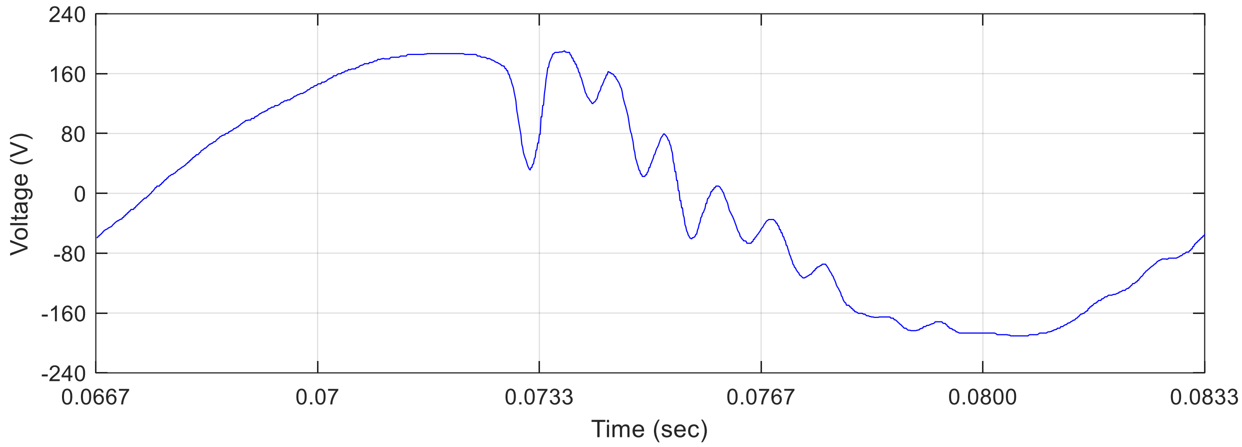


Waveform capture:

- starts at $C_{\text{before}} = 4$ cycles before the distorted cycle
- ends at $C_{\text{after}} = 5$ cycles after the distorted cycle

4.2. Event-Triggered Waveform Capture

- **Example 4.5 (Cont.)**: The waveform is highly distorted during cycle #5:



- The distortion is due to a *momentary ringing event* that was caused by *resonances* formed between a capacitor bank and an inductive load during an upstream fault in a distribution system [210].

- The *damping oscillations* in this event will be analyzed in Example 4.18.

4.2. Event-Triggered Waveform Capture

Event Detection in Waveform Measurements

• There are different methods to detect an event to *trigger* event capture.

• The main idea in most waveform event detection methods is to *compare* the measured waveform with a *reference* waveform.

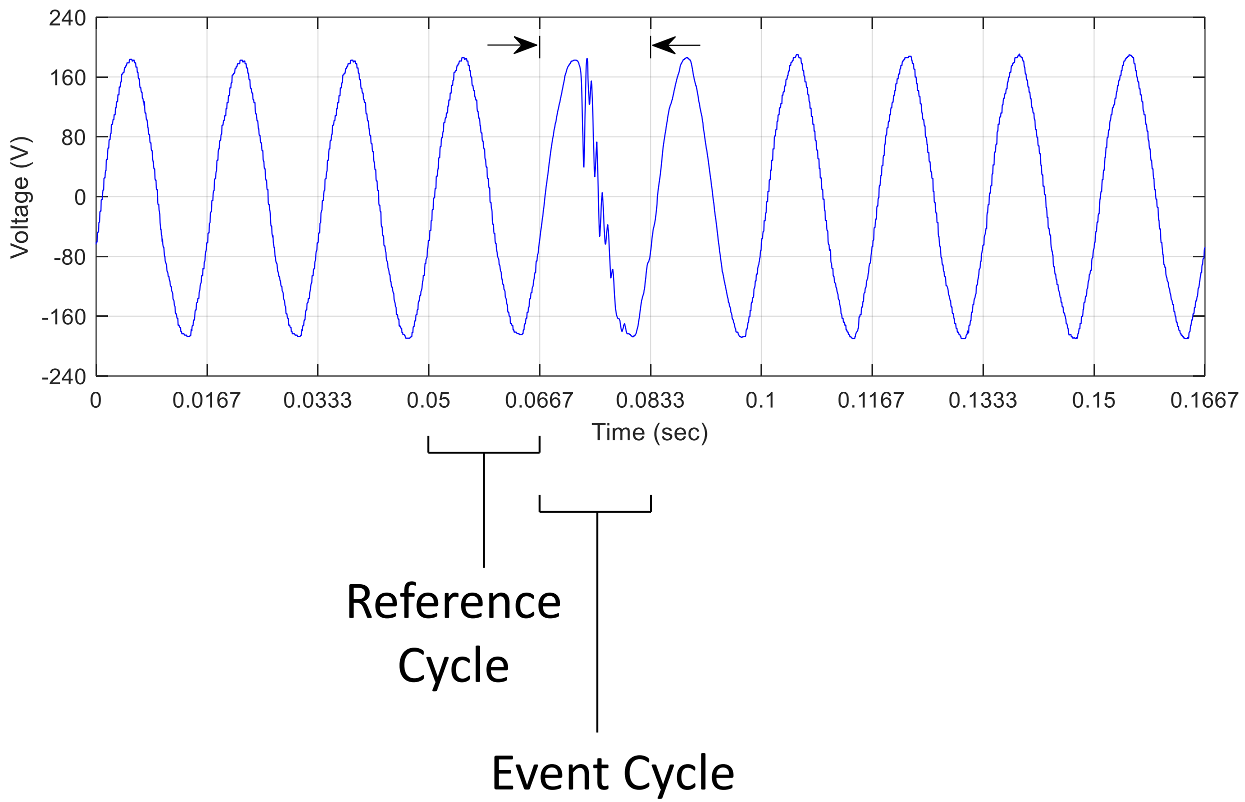
To represent the *normal* behavior of the system.

• If there is a considerable difference between the measured waveform and the reference waveform, then it can infer *abnormal* behavior.

which in turn can *trigger* an event capture.

4.2. Event-Triggered Waveform Capture

- In practice, it is very common to simply *compare two consecutive cycles*, i.e., to take the waveform in the previous cycle as the reference to detect an event in the waveform in the present cycle.

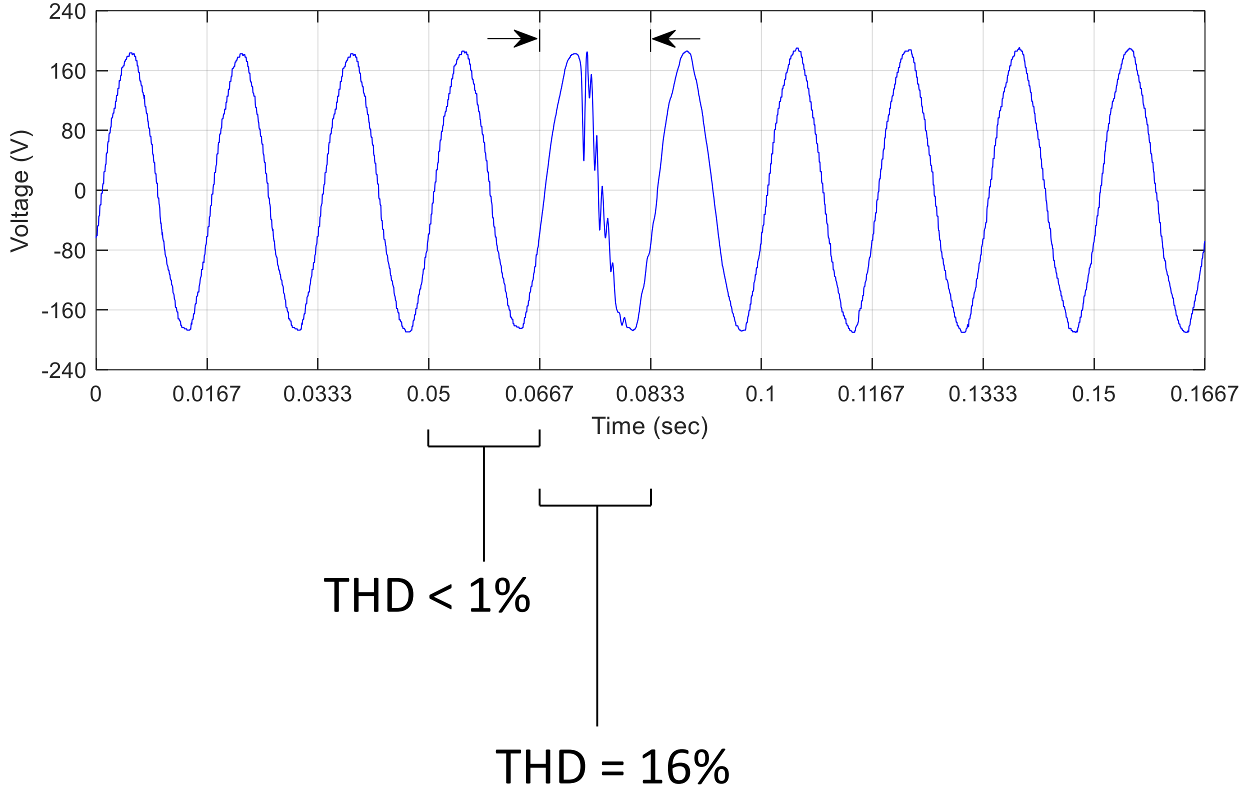


4.2. Event-Triggered Waveform Capture

- There are different ways to compare two cycles of waveforms, such as:
    - Comparing THD
    - Comparing RMS
    - Point-to-Point Comparison
    - Comparing Sub-Cycle RMS
    - Differential Waveform
    - Neutral Current Waveform
    - Other Factors and Methods
- Next, we go through the above options and discuss their differences.

4.2.1. Comparing THD

- Compare two consecutive waveform cycles based on their THD values.



4.2.1. Comparing THD

• What matters here is the *change* in THD from one cycle to the next:

$$\Delta\mathrm{THD} = \mathrm{THD}(\mathrm{Current\ Cycle}) - \mathrm{THD}(\mathrm{Previous\ Cycle})$$

• Importantly, the value of THD by itself is not important. This is because a high THD in a cycle does *not* necessarily mean the presence of an event. It could also indicate a steady-state waveform distortion; see Section 4.1.

• Thus, it is rather a *change* in THD that indicates a *change* in waveform. In this regard, we can check the following inequality to detect an event:

$$|\Delta\mathrm{THD}| \geq \alpha_{\mathrm{THD}}$$

4.2. Event-Triggered Waveform Capture

4.2.1. Comparing THD

- Parameter α_{THD} is a predetermined threshold.

- For example, if we set $\alpha_{\text{THD}} = 5\%$, then we detect an event if the THD in each cycle of the waveform suddenly changes by 5% or more.

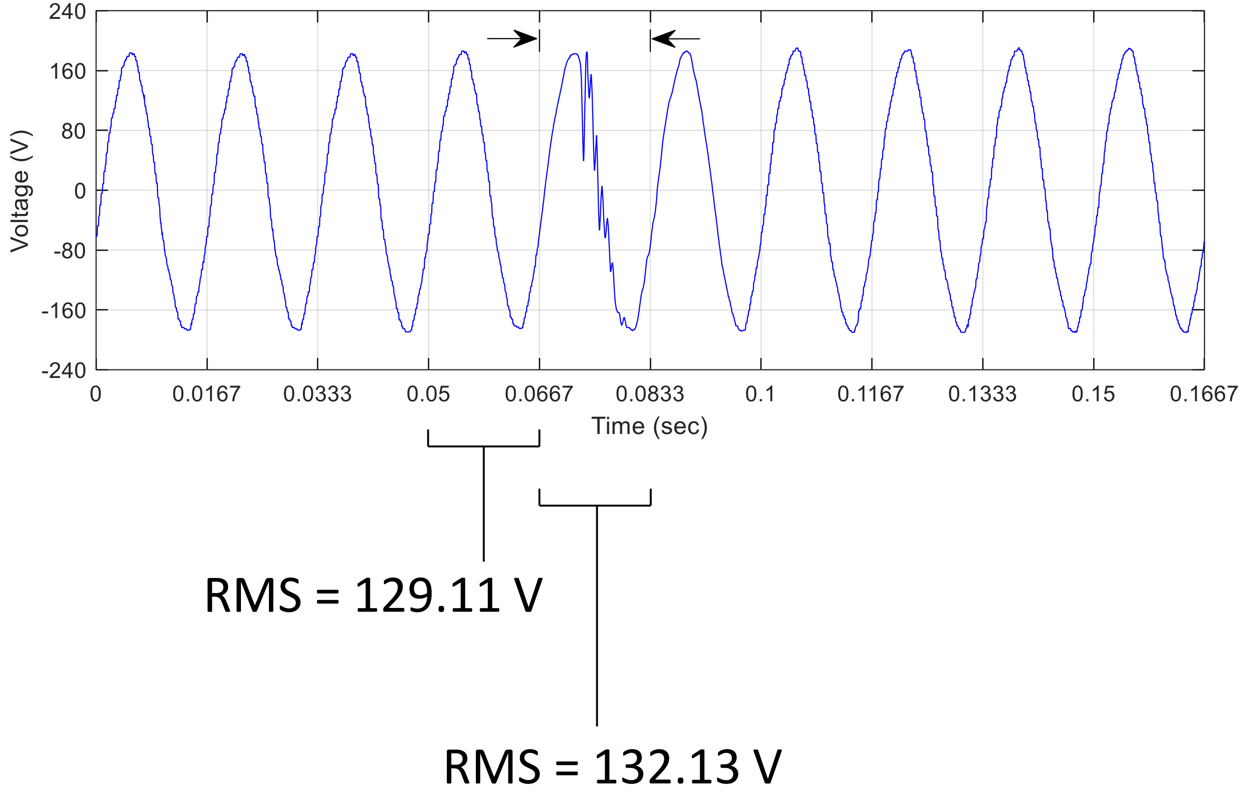
- Note that, both *positive changes* and *negative changes* in THD are of interest here because both indicate changes in waveshape.

- A negative change in THD indicates *reduction* in waveform distortion.

  - Meaning that the source of distortion is removed or mitigated.

4.2.2. Comparing RMS

- Compare two consecutive waveform cycles based on their RMS values.



4.2.2. Comparing RMS

- Again, what matters is the *change* in RMS from one cycle to the next:

$$\Delta\text{RMS} = \text{RMS}(\text{Current Cycle}) - \text{RMS}(\text{Previous Cycle})$$

- We can check the following inequality to detect an event:

$$|\Delta\text{RMS}| \geq \alpha_{\text{RMS}}$$

- It is common to *normalize* $|\Delta\text{RMS}|$ with respect to the RMS value of the reference cycle. In that case, the threshold α_{RMS} would be in percentage.

4.2. Event-Triggered Waveform Capture

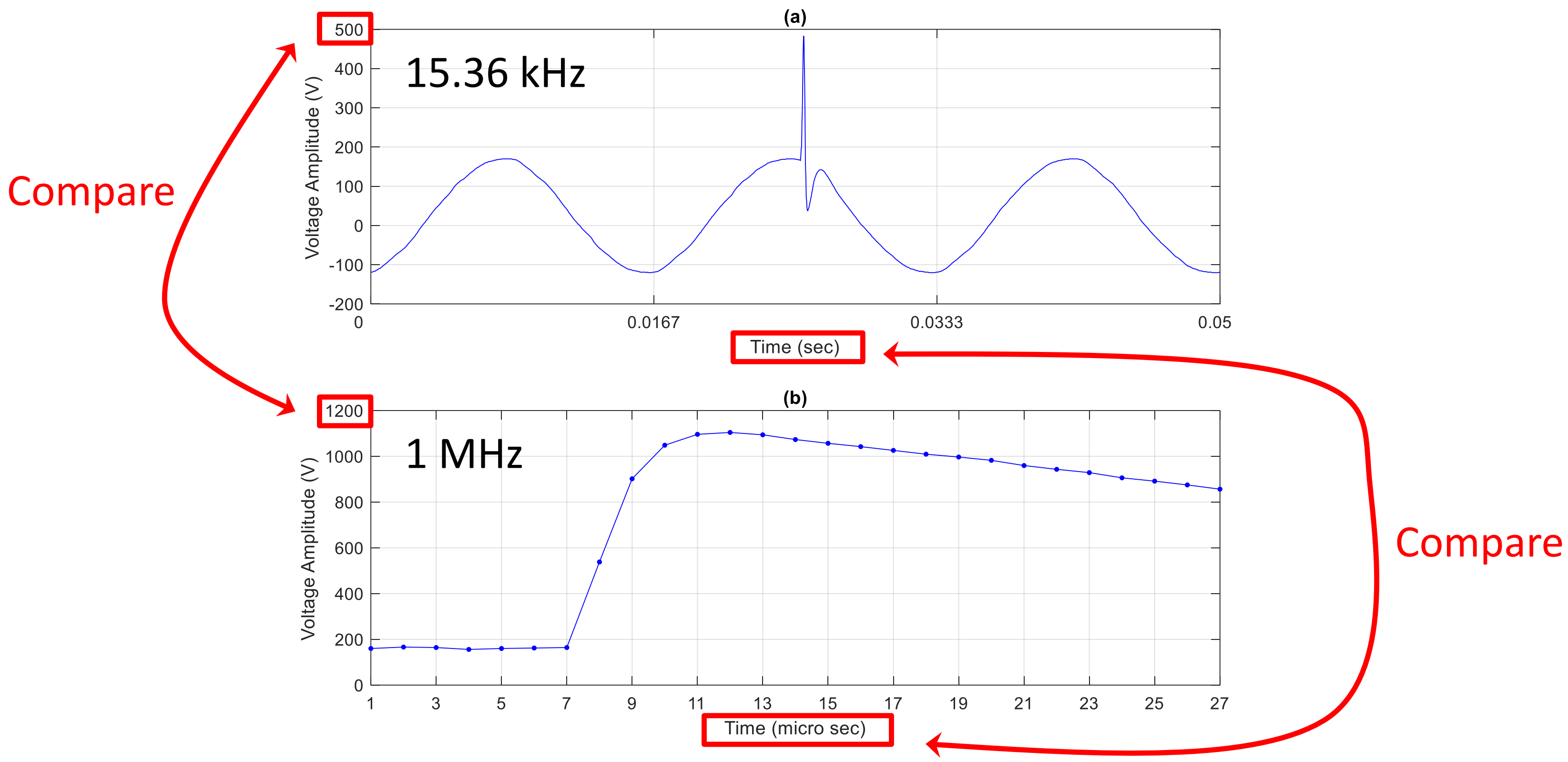
4.2.2. Comparing RMS

• The extend of change in the RMS value may depend on the *sampling rate* of the waveform sensor. This is particularly true if the event is an *impulse* that lasts only a very short period of time.

• **Example 4.6**: Consider the voltage waveform measurements in the top figure on the next slide. The *impulse* in the second cycle is due to a *lightning strike*. The resolution of the waveform in this figure is 256 samples per cycle, or 65 microseconds per sample. The impulse appears to peak at 483 V. Next, consider the same waveform, but this time captured by a waveform sensor with a 1 MHz sampling rate, or 1 microsecond per sample, as shown in the bottom figure. The impulse now appears to peak at 1104 V. The second sensor provides a more accurate representation of this extremely fast impulse event.

4.2.2. Comparing RMS

- **Example 4.6 (Cont.)**: The impact of sampling rate:



4.2. Event-Triggered Waveform Capture

4.2.3. Point-to-Point Comparison

- Compare two consecutive waveform cycles sample by sample.

- An event is detected if the sample-by-sample difference exceeds a *magnitude threshold* and it lasts longer than a *minimum duration threshold*.

- However, there are several challenges in using this approach.

- One challenge in conducting point-to-point waveform comparison is the need to *precisely* identify the *beginning* and the *end* of each cycle.

  - This can be done by *detecting the zero-crossing points*; see Appendix A1 in [212]. But identifying the boundaries of each cycle is prone to error.

4.2. Event-Triggered Waveform Capture

4.2.3. Point-to-Point Comparison

• Another challenge is when the two waveform cycles do *not* have the same *frequency*, due to the changes in the frequency of the power system.

  • See Section 2.9 in Chapter 2 about the changes in frequency.

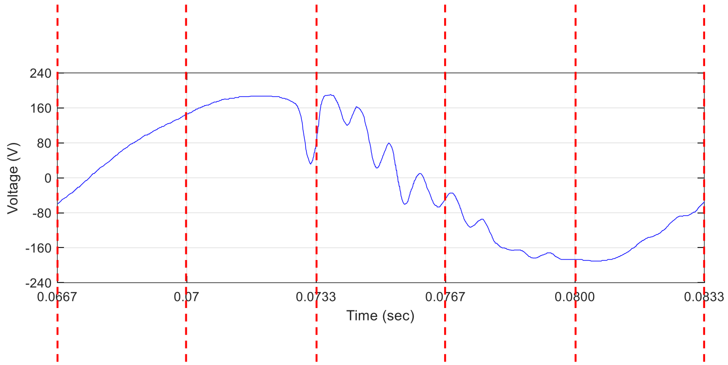
  • The potential remedy is to do *frequency variation correction*; see [213]. However this type of correction itself is prone to error.

• Point-to-point comparison may *not* be a good approach in practice. It may catch a lot of inconsequential events or miss important events.

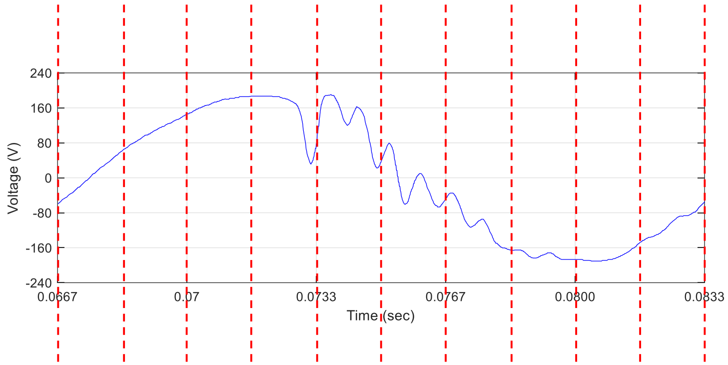
4.2.4. Comparing Sub-Cycle RMS

• This method is a *trade-off* between the point-to-point comparison (in Section 4.2.2) and the RMS value comparison (in Section 4.2.3).

• In this method, each of the two waveform cycles is *divided* into M segments, where M is an integer number between 4 and 16.



$M = 5$



$M = 10$

• An RMS value is calculated for *each segment* for each waveform cycle.

4.2.4. Comparing Sub-Cycle RMS

- The difference between the RMS values is then calculated across the two consecutive waveforms in order to obtain:

$$\Delta\mathrm{RMS}[1], \ldots, \Delta\mathrm{RMS}[\mathrm{M}].$$

- An event is detected if the following condition holds:

$$|\Delta\mathrm{RMS}[i]| \geq \alpha_{\mathrm{SCRMS}} \qquad \exists i = 1, \ldots, M$$

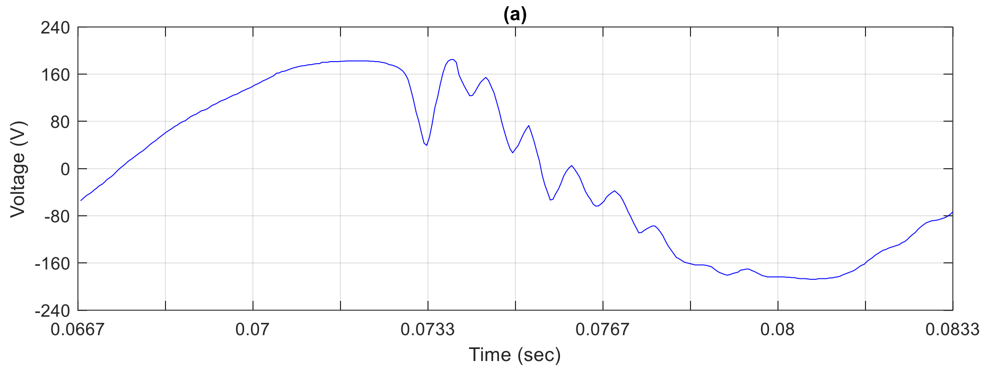
- It is common to normalize $|\Delta\mathrm{RMS}[i]|$ with respect to the RMS value of sub-cycle i in the reference cycle. In that case, α_{SCRMS} is in percentage.

- If $M = 1$, then the above method reduces to comparing the RMS values.

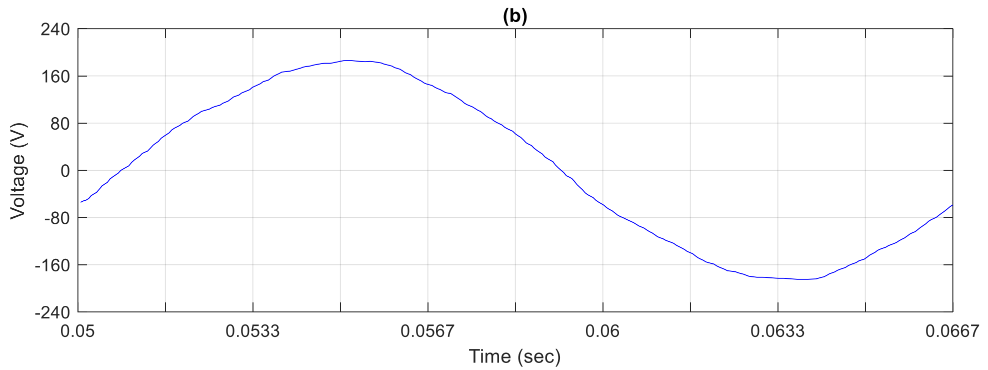
4.2.4. Comparing Sub-Cycle RMS

- **Example 4.7**: Consider the ringing event in voltage in Example 4.5.

Event Cycle:



Reference Cycle:

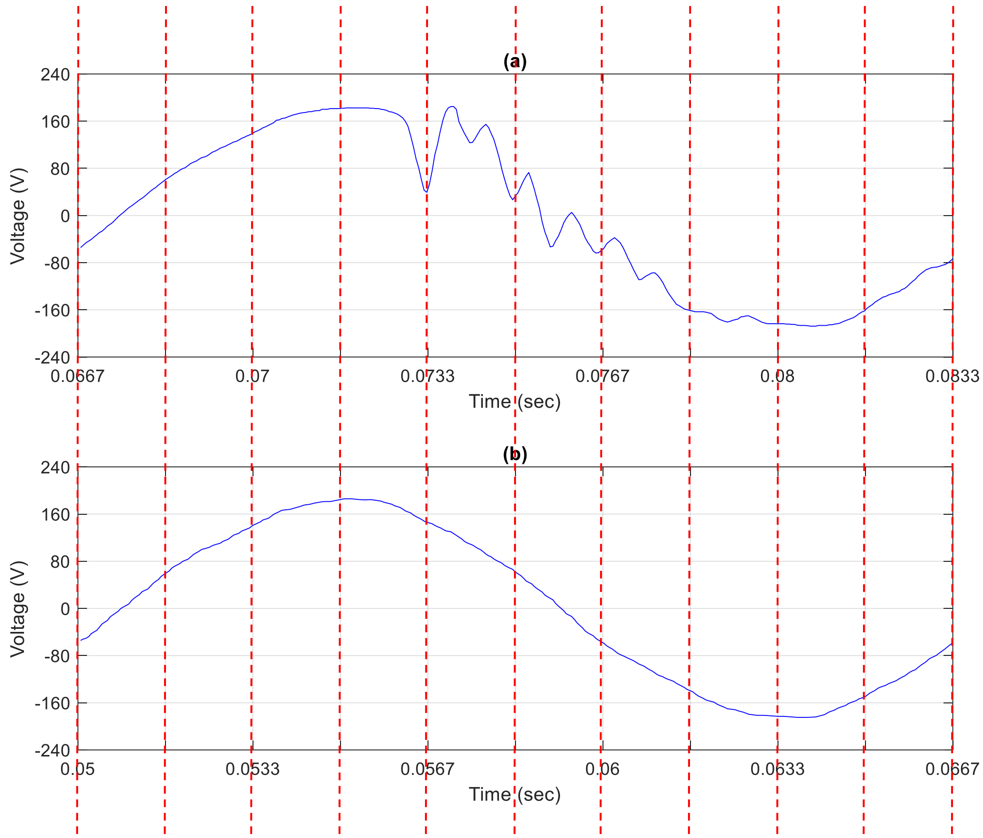


4.2.4. Comparing Sub-Cycle RMS

- **Example 4.7 (Cont.)**: Suppose $M = 10$.

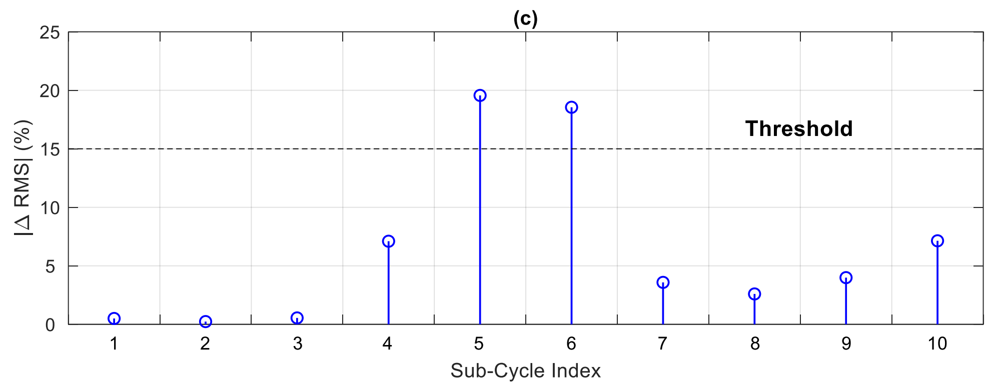
Event Cycle:

Reference Cycle:



4.2.4. Comparing Sub-Cycle RMS

• **Example 4.7 (Cont.)**: The absolute differences between the RMS values of the corresponding sub-cycles across the two waveforms are obtain as:



$\alpha_{\text{SCRMS}} = 15\%$

• Some of the sub-cycle RMS values have gone up to almost 20%. This is in sharp contrast with the comparison of the *full-cycle* RMS values on Slide 47, where the absolute difference was only 2.34%.

• If $\alpha_{\text{SCRMS}} = 15\%$, then the event is detected in sub-cycles 5 and 6.

4.2.5. Differential Waveform

- This method investigates the abnormalities that are *superimposed* to the normal voltage or normal current waveforms during an event.

- It works based on obtaining the following differential waveform:

$$\Delta x(t) = x(t) - x(t - NT).$$

where $x(t)$ is the measured current waveform or voltage waveform; T is the waveform interval, i.e., $T = 1/60$ second for a 60 Hz waveform; and N is a small integer number, such as 1, 2, 3, 4, or 5.

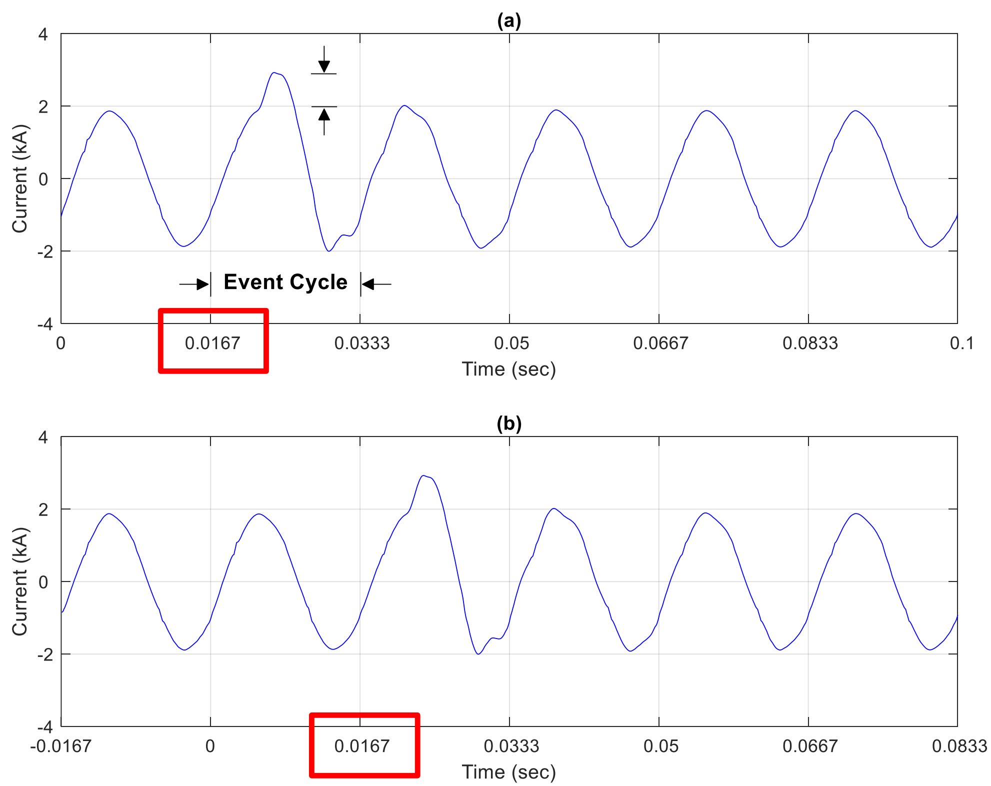
- We can detect an event based on the characteristics of $\Delta x(t)$.

4.2.5. Differential Waveform

- **Example 4.8**: Consider the current waveform measurements below:

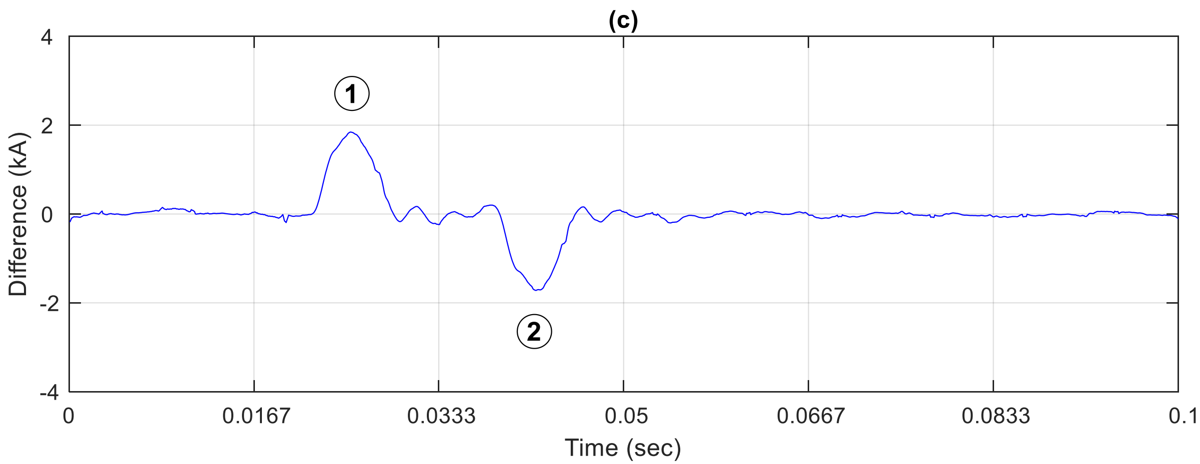
$x(t)$

$x(t-T)$



4.2.5. Differential Waveform

- **Example 4.8 (Cont.)**: The differential waveform is obtained as:



- We can see that the event has created two distinct blips in the differential waveform, which are denoted by ① and ②.

- Note that *both* of them are associated with the *same* event. (Q: Why?)

4.2. Event-Triggered Waveform Capture

4.2.5. Differential Waveform

- There are multiple ways to use differential waveform to detect an event.

- One is to check the absolute value of the instantaneous waveform.

- In this option, an event is detected if the absolute value of the differential waveform exceeds a *magnitude threshold* and it lasts longer than a *minimum duration threshold*.

- For instance, for each of the two blips in the figure on Slide 60, the absolute value exceeds 1.5 kA, and it lasts for over a quarter of a cycle.

- It is clear that this first option is somewhat similar to the point-to-point comparison that we saw earlier in Section 4.2.3.

4.2.5. Differential Waveform

• Another option is to treat the differential waveform as a *signal* by itself.

• Accordingly, we can apply Fourier analysis or Wavelet analysis to the differential waveform to perform a *frequency-domain* analysis.

• A threshold can be applied to the magnitude of the fundamental frequency component, or the magnitude of the dominant frequency component (if different from fundamental frequency) of the differential waveform based on each cycle or multiple consecutive cycles [212].

4.2.6. Neutral Current Waveform

• Many events are *asymmetric* and take place only in one phase, such as in the case of a single-phase-to-ground fault. Even if an event occurs in all three phases, it is unlikely that it affects all three phases equally.

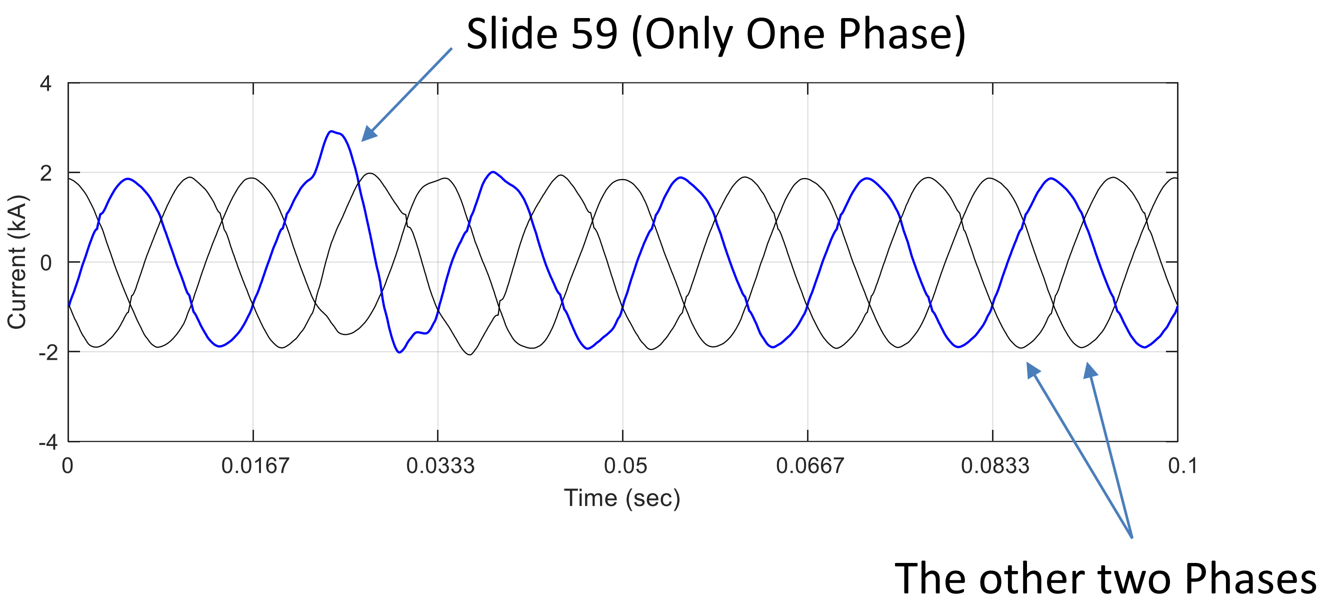
• Therefore, we may detect an event in waveform measurements by examining the *neutral current* (either measured or calculated):

$$i_{\mathrm{N}}(t) = i_{\mathrm{A}}(t) + i_{\mathrm{B}}(t) + i_{\mathrm{C}}(t).$$

• Note: This is relevant only to three-phase waveform measurements.

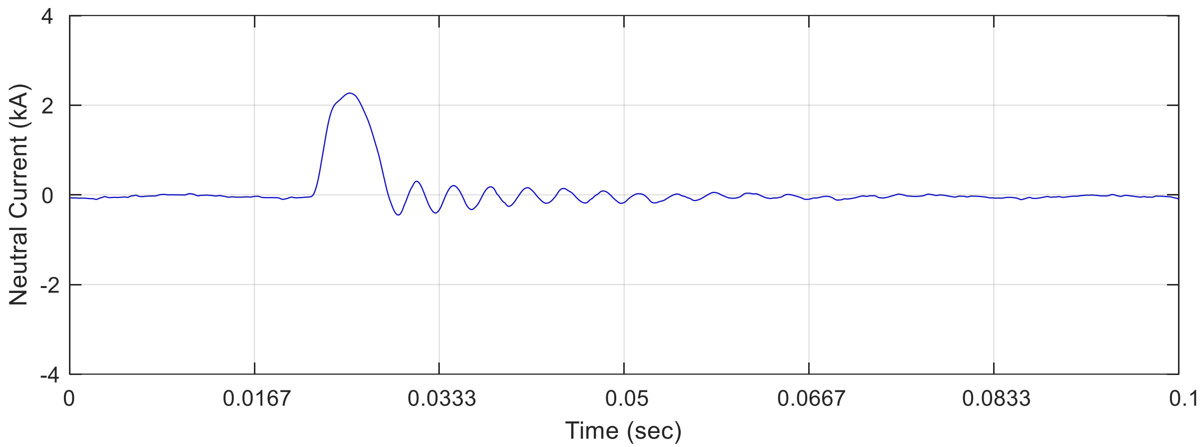
4.2.6. Neutral Current Waveform

- **Example 4.9**: Again, consider the current waveform measurements in Example 4.8 on Slide 59. This time, let us look at *all three phases*:



4.2.6. Neutral Current Waveform

• **Example 4.9 (Cont.)**: The neutral current is obtained as:



• The event creates a significant signature in the neutral current waveform during the event. This signature can be used to detect the abnormality, e.g., by using a threshold on the magnitude of the neutral current.

4.2.6. Neutral Current Waveform

- **Example 4.9 (Cont.)**: Notice that the neutral current waveforms on Slide 65 shows some transient oscillations (with a frequency higher than the fundamental) that damp down within a few cycles after the event occurs.

- Interestingly, such clear oscillations are *not visible* in the original three-phase current waveform measurements on Slide 64.

- Therefore, looking at the neutral current can be generally beneficial and informative about the event, apart from helping with event detection.

4.2.6. Neutral Current Waveform

• There are a few advantages in analyzing the neutral current waveform instead of (or in addition to) the differential current waveform.

• For example, one advantage is that the neutral current waveform does *not* manifest the *confusing second blip* that we saw on Slide 60.

• As in the case of differential waveform, neutral current waveform can too be analyzed not only in time-domain but also in frequency-domain.

4.2.7. Other Factors and Methods to Trigger Waveform Capture

- An event in waveform measurements also can be defined based on a *change in frequency*. This will allow capturing the waveform during frequency events, such as the one in Example 2.23 in Chapter 2.

- Furthermore, an event also may be defined based on a *combination of multiple parameters and factors*, such as a certain change in THD and simultaneously a certain change in RMS value (or other metrics).

- If communications and precise time synchronization are available across multiple waveform sensors, then one may also define an event based on simultaneous change of waveform parameters at different locations [256].

    - See the "synchronized waveform measurements" in Section 4.6.

4.2.7. Other Factors and Methods to Trigger Waveform Capture

• Selecting the right thresholds is critical in event-triggered waveform captures. If the thresholds are set *too high*, then important events are missed. If they are set *too low*, then many false triggers are generated.

• All trigger mechanisms work in parallel.

• Therefore, one physical event may trigger *multiple trigger mechanisms* in the same waveform sensor, such as THD and RMS value, at the same time.

• Of course, the same physical event, may also trigger waveform capture at *multiple waveform sensors*, depending on the nature of the physical event and the locations of the waveform sensors on the network.

Table of Contents

4.3 Analysis of Events and Faults in Waveform Measurements

- Once an event is detected and captured, the next step is to analyze the extracted waveform in order to obtain some sort of *useful information* from the event, such as to determine the *cause* of the abnormality.

- In most cases, the event in waveform measurements is due to minor power quality issues; such as some occasional load behavior.

- However, there are also events that are due to *faults* or *incipient faults*.

- Analysis of such events is particularly important because some events show whether or not the power system and its various equipment and apparatus are in a safe and healthy state of operation.

  - We will review several *waveform signatures* of such events.

4.3 Analysis of Events and Faults in Waveform Measurements

- An *incipient fault* is an early-stage fault in the system that could become a catastrophic failure in the future if it is not address and fixed.

- Incipient faults are usually *self-clearing* (i.e., they are extinguished by natural physical reasons before the utility protective devices have time to operate to clear them) and they last for only a *short period of time*, such as only a *fraction* of a cycle or up to only two or three cycles.

- Nevertheless, capturing incipient faults is important; because by capturing the problem at its early stages, we may prevent a potential catastrophic fault in the future, before it gets much worse.

4.3 Analysis of Events and Faults in Waveform Measurements

- Note: Equipment failures and incipient faults often demonstrate unique signatures in *current waveforms* [212]. Paying attention to the current waveform will help us distinguish them from power quality issues.

- Thus, for the discussions in this section, attention should be paid not only to *voltage waveforms* but also particularly to *current waveforms*.

4.3.1. Faults in Underground Cables

• Failures in underground cables are gradual and take place over time.

• They are often caused by *moisture penetration* into the *cable splice* (connection of two cables), which results in breakdown of the cable insulation.

Example cable joints at the time of installation, for connecting and splicing medium and high voltage underground cables.

www.powerandcables.com

• The water produces an *arc*; but then the arc quickly evaporates water, which in turn *extinguishes the arc*, making the fault *self-clearing* [216].

4.3.1. Faults in Underground Cables

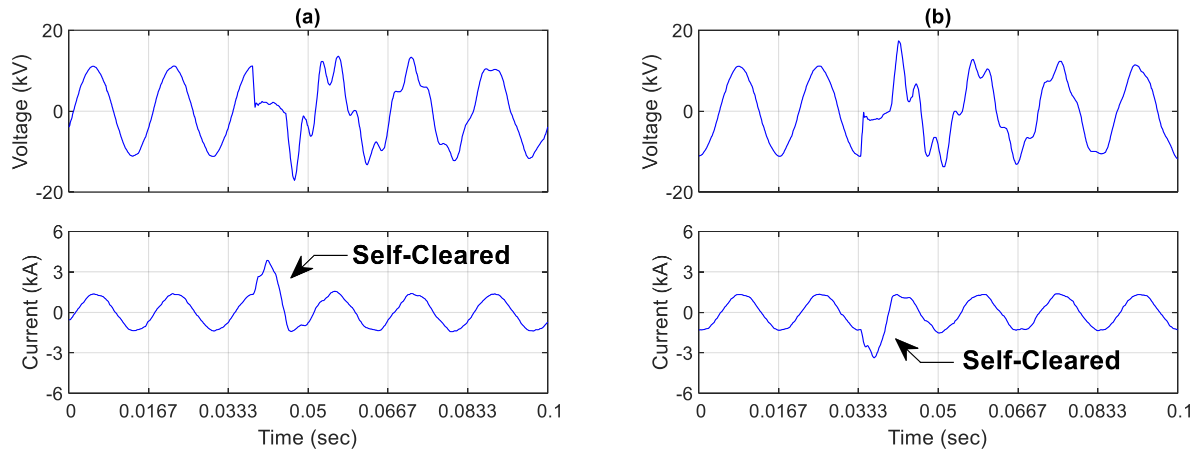
• The self-healing nature of the above fault means that it does not trigger any overcurrent protection device; hence, it can go unnoticed for a while.

• However, these incipient faults may ultimately turn into permanent faults after self-clearing many times and *gradually damaging the cable*.

• Once they turn permanent, they will cause the operation of the power system protection devices; losing service for several utility customers.

4.3.1. Faults in Underground Cables

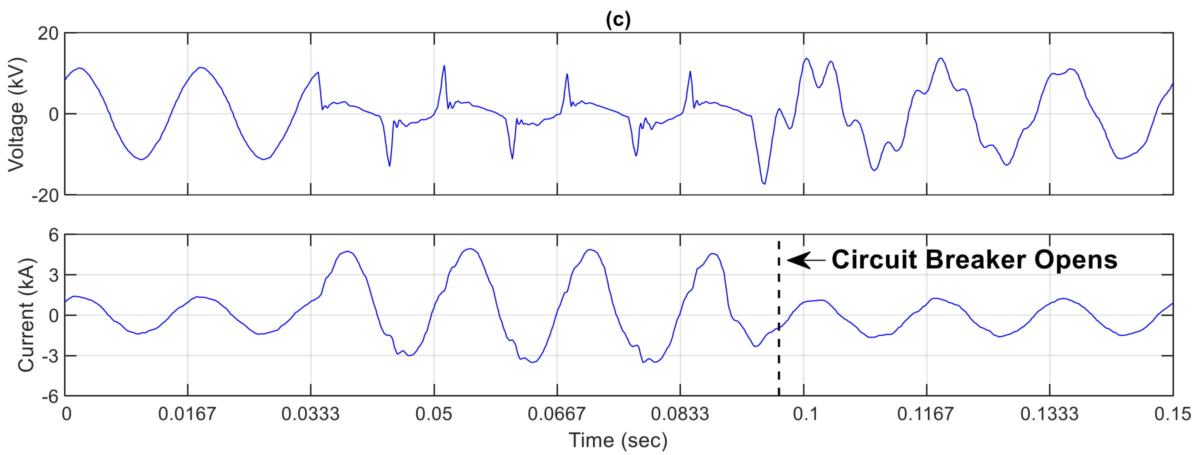
- **Example 4.10**: Her are the voltage and current waveforms during two *sub-cycle self-clearing faults* in the *same* underground cable [214].



- The second fault takes place only about *1.5 hours after* the first fault.

4.3.1. Faults in Underground Cables

- **Example 4.10 (Cont.)**: Two days later, yet another fault took place on the same underground cable. This time the fault lasted for 3 cycles, and it was cleared by an over-current circuit breaker which isolated the faulted area.



- The first two faults were *incipient* faults.

- They were followed by a *permanent* fault (the third fault).

4.3.1. Faults in Underground Cables

• Faults in underground cables can happen also in the cable termination (where the cable is brought above the ground) or cable insulation.

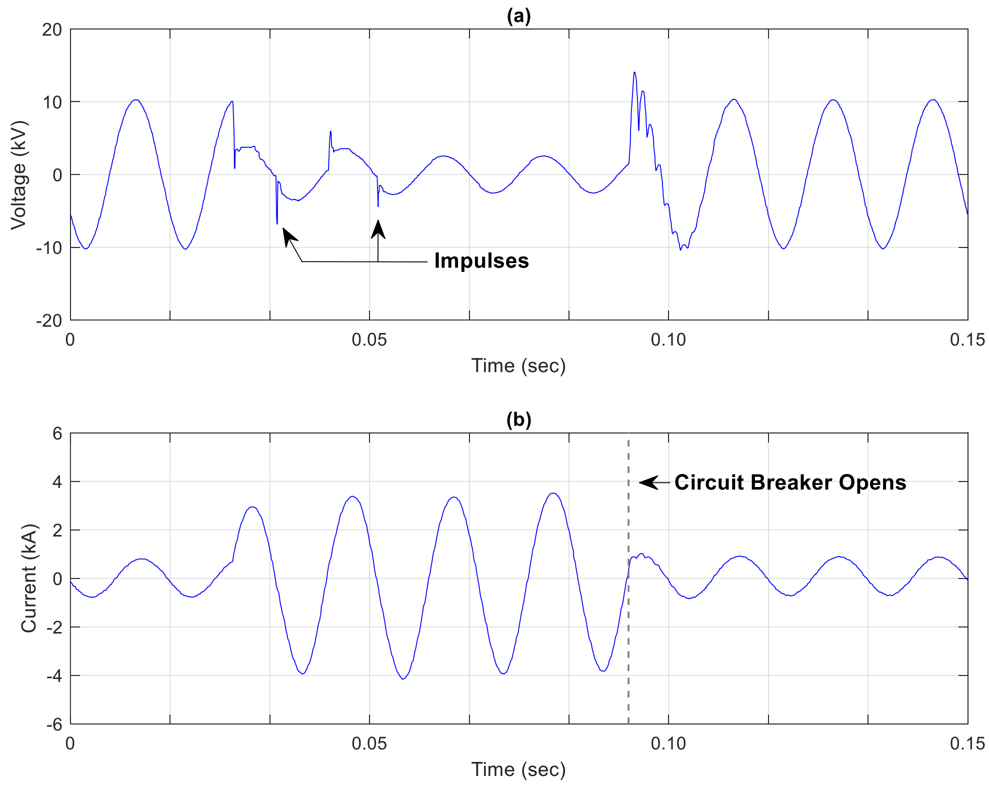
• Depending on where the fault occurs, it may create different waveforms.

• For example, the figure on the next slide shows the waveform measurements during a fault at a *cable termination* location.

• Notice the *impulses* in the faulted voltage waveform during the first two cycles of the event. However, not all cable termination faults demonstrate impulses. There are some methods to apply to the captured waveform measurements of the fault in order to identify whether the fault took place at the cable joint, cable insulation, or cable termination; cf. [217].

4.3.1. Faults in Underground Cables

- This fault (in cable terminator) is explained on the previous slide [217]:



4.3.2. Faults in Overhead Lines

- Failures in overhead transmission and distribution lines are often due to short-circuit conditions that can be caused in different ways, such as:

  - Tree contact
  - Animal contact
  - Traffic accidents
  - Lightning

- Some of these causes are *sudden* with *no precursor* conditions.

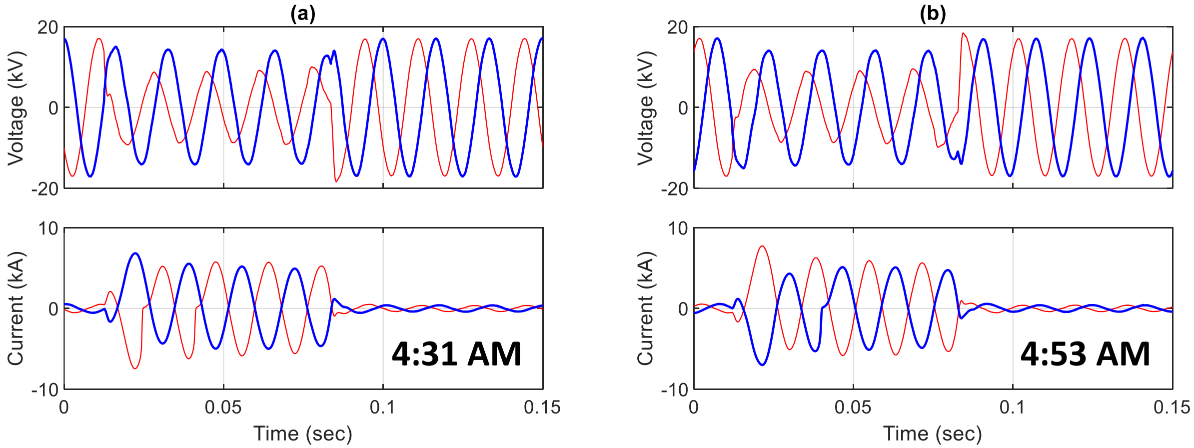
4.3.2. Faults in Overhead Lines

- Failures in overhead transmission and distribution lines are often due to short-circuit conditions that can be caused in different ways, such as:
  - Tree contact
  - Animal contact
  - Traffic accidents
  - Lightning

- However, some other causes may *repeat* and *evolve* into a major outage. For example, this can happen to tree contacts, due to *growth in vegetation* or during *storms and windy weather* conditions.

4.3.2. Faults in Overhead Lines

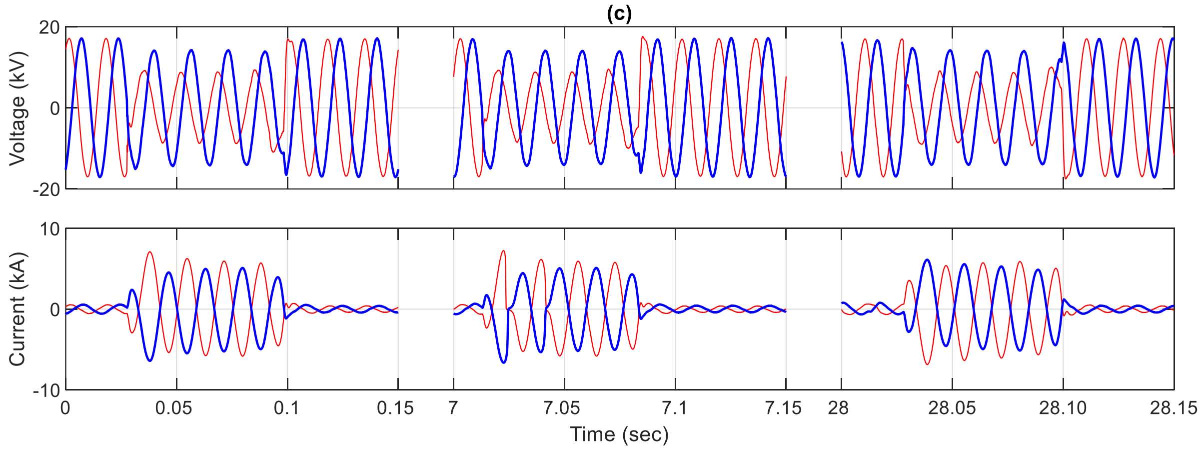
- **Example 4.11**: Here are two faults that are caused by *tree contacts* to an overhead line during *windy* weather conditions. The first fault happened at 4:31 AM. The second fault happened at 4:53 AM. Both faults affected only two of the three phases. Only the affected phases are shown here.



- Both faults were cleared by the circuit breakers in the power system.

4.3.2. Faults in Overhead Lines

- **Example 4.11 (Cont.)**: As the storm intensified, so did the frequency of the faults that were caused by tree contacts. For instance, at 5:01 AM, *three separate faults* took place *within one minute*. All of them again lasted for about four cycles before they were cleared by the re-closer.



5:01 AM (three separate faults in one minute)

4.3.2. Faults in Overhead Lines

• The observations in Example 4.11 can be used to improve safety.

• For example, if a geographical area shows an increasing number of tree contacts during dry and windy weather conditions, the utility may choose to shut down power in the high-risk locations to prevent *wildfire*.

• Another application is to *cut vegetation* around overhead lines when the number of faults caused by tree contacts exceeds a certain threshold.

www.smart-energy.com

4.3.3. Faults in Transformers

• Failures in transformers can happen in *tap changer*, *bushing*, *winding*, etc.

• Early detection of these failures can allow for corrective actions to prevent costly outages and reduce downtimes.

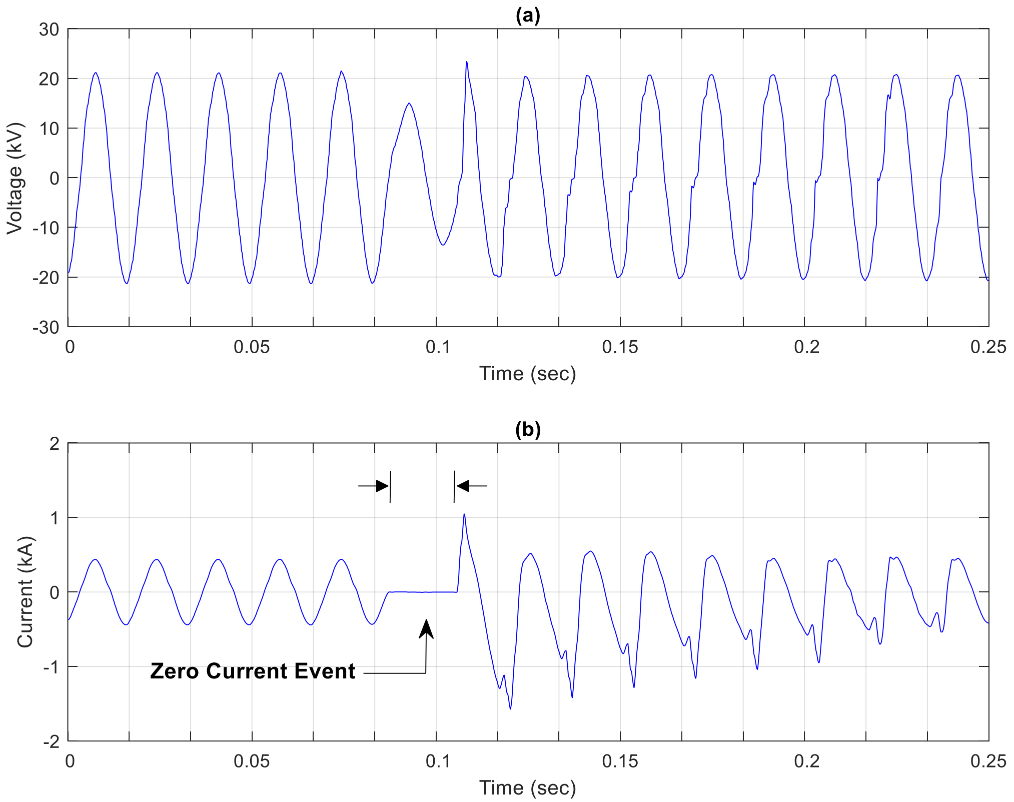
• **Example 4.12**: The figure on the next slide shows the voltage and current waveforms during a transformer tap changer incipient failure [220].

• The fault occurred during tap changing, and it caused zero current.

• Only the faulted phase is shown here (on the next slide).

4.3.3. Faults in Transformers

- **Example 4.12 (Cont.)**: Initially, the fault occurred occasionally, and the duration of the *zero current period* was less than one cycle.



4.3.3. Faults in Transformers

- **Example 4.12 (Cont.)**: However, over several days, the abnormality took place *more frequently* and *repeated* multiple times every day.

- The duration of the *zero current period* also gradually increased.

- When technicians inspected the tap changer, they discovered *a pin that was shearing* and causing *arcing* during the travel of the tap changer.

- Utility technicians reported that the transformer would have faced a catastrophic failure within two weeks of the inspection if the arcing in the transformer had not been detected and fixed [220].

4.3.4. Faults in Capacitor Banks

• Capacitor switching transient is one of the most common equipment switching events in power systems. Analyzing the voltage and current waveform measurement during capacitor bank switching is informative.

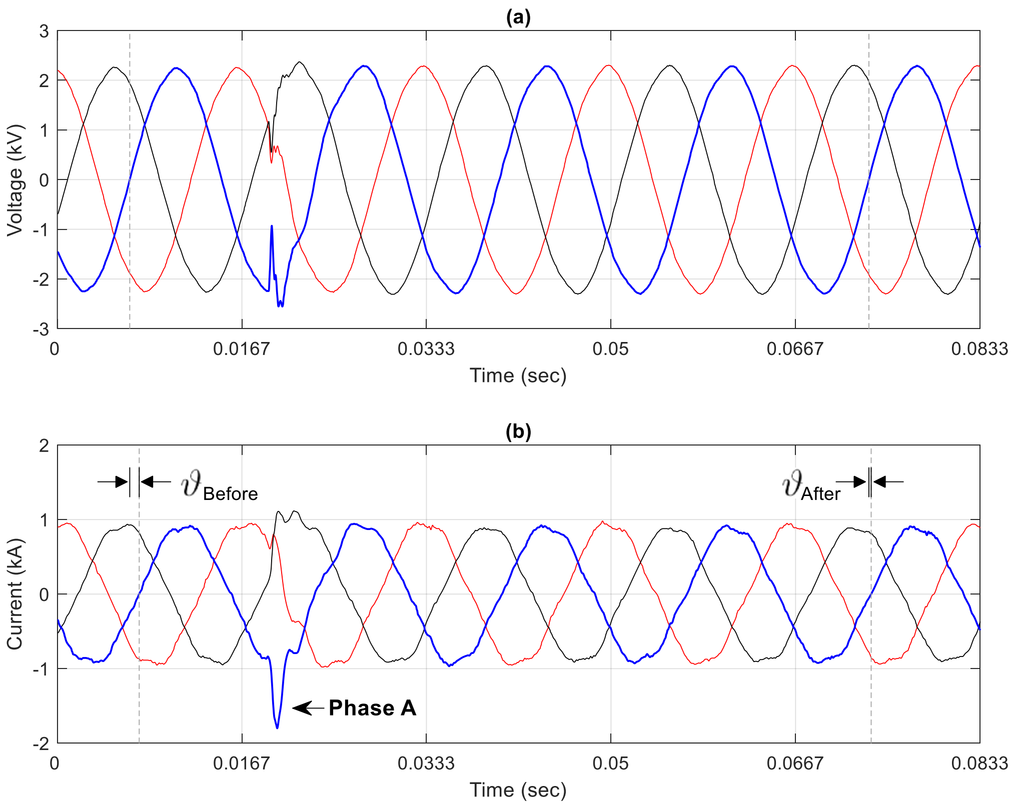
• First, we can identify whether the capacitor bank was *energized*, i.e., it was switched "on," or *de-energized*, i.e., it was switched "off."

• Second, we can characterize the switching transient behavior, such as with respect to the *frequency* and *duration of oscillations*, *switching angle* at each phase, or *balanced or unbalanced* operation.

• Third, we can evaluate the state of the health of the capacitor and its various components and identify the presence of *faults* or *incipient faults*.

4.3.4. Faults in Capacitor Banks

• **Example 4.13**: Voltage and current waveforms are measured at a distribution substation during a *capacitor bank switching* event.



4.3.4. Faults in Capacitor Banks

• **Example 4.13 (Cont.)**: The phase angle difference between voltage and current are marked for Phase A, both *before* and *after* the event. They are denoted by $\vartheta_{\text{before}}$ and ϑ_{after}. They are obtained as:

$$\vartheta_{\text{before}} = \frac{0.9231\,\text{msec}}{16.6667\,\text{msec}} \times 360 = 19.94^\circ \quad \Rightarrow \quad \text{PF} = 0.940$$

$$\vartheta_{\text{after}} = \frac{0.4103\,\text{msec}}{16.6667\,\text{msec}} \times 360 = 8.86^\circ \quad \Rightarrow \quad \text{PF} = 0.988.$$

• The power factor has considerably *increased* after the event. Thus, the capacitor is *energized*. Similar analysis can be done on Phase B, where PF increases from 0.950 to 0.992, and on Phase C, where PF increases from 0.955 to 0.995. The capacitor bank has an almost *balanced* operation.

4.3.4. Faults in Capacitor Banks

• The transient behavior in Example 4.13 is generally considered *normal*.

• Note that, during the energization of a capacitor bank, its capacitance interacts (resonates) with the inductance of the rest of the power system; which gives rise to *transient oscillations*.

• The oscillations in voltage may peak between 1.1 and 1.4 per unit.

• The frequency of the transient oscillations is typically between 300 Hz and 1000 Hz. For the transient oscillations in Example 4.13, the frequency is about 300 Hz [221].

4.3.4. Faults in Capacitor Banks

• Capacitor switching transients can be minimized by energizing the capacitor *at or near* a zero-crossing point of the voltage waveform.

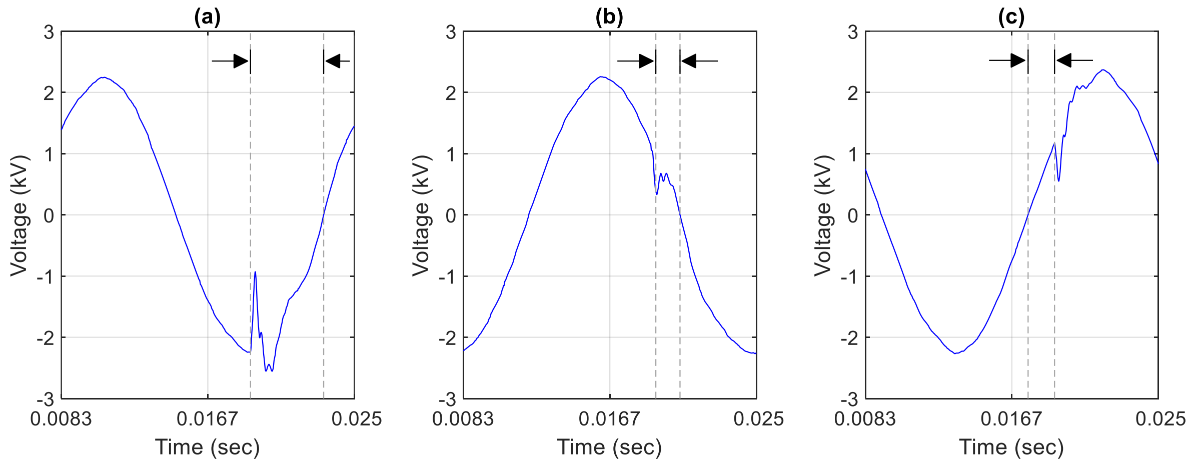
• Performing switching at such precise times can be achieved by using a mechanism called *synchronous switching control*.

• In practice, if the phase angle of voltage at the time of energizing each phase is between -5° and $+5^\circ$ of the voltage zero-crossing point on that phase, then switching is considered to be synchronous [221].

• The switching phase angles across the three phases during the capacitor energizing event in Example 4.13 are shown on the next slide

4.3.4. Faults in Capacitor Banks

• In Example 4.13, the closing at Phase A is premature by 89.6°; the closing at Phase B is premature by 23.9°; and the closing at Phase C is delayed by 37.2°. It is clear that synchronous closing control was not successful, particularly at Phase A (which resulted in large transients).



• Synchronous closing control was *not* successful, particularly on Phase A.

4.3.5. Faults in Other Devices and Equipment

- The cases in Section 4.3.5 are only a few examples of the *fault signatures* that can be captured and analyzed using waveform sensors.

- The power system has many devices, equipment, and apparatus.

- Each one may manifest its unique signatures in voltage and/or current waveform measurements during a variety of fault scenarios.

- Other examples include the analysis of faults in:

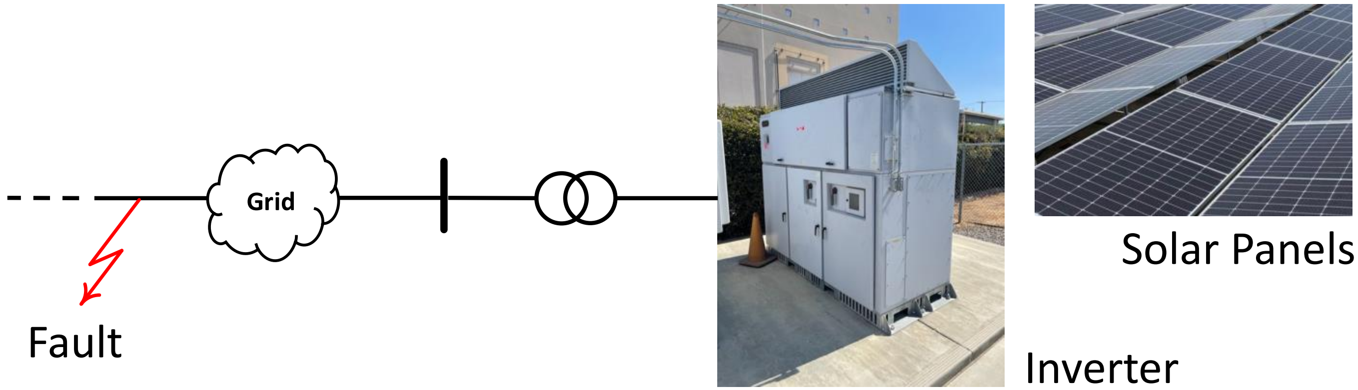
    - Circuit breakers [212, 223]
    - Surge arresters [215, 224]
    - Switching devices [225, 226]
    - Inverters and other power electronics devices [227–229]

4.3.6. Impact of Faults on DERs

- Q: How do different equipment and devices *respond* to a fault?

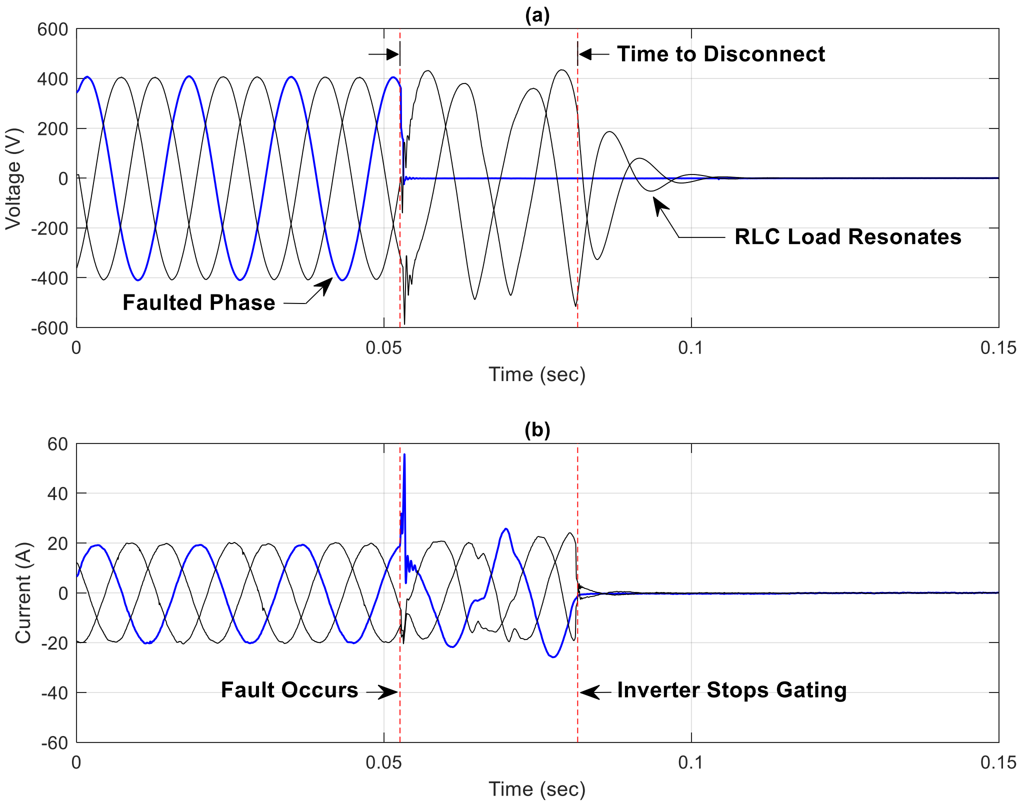
- Answering this question is particularly critical when it comes to *inverter-based resources*, such as most DERs (Distributed Energy Resources).

- Examples of inverter-based resources include PVs, wind turbines, stationary batteries, and grid-connected electric vehicles.



4.3.6. Impact of Faults on DERs

- **Example 4.14**: The voltage and current waveforms of a three-phase 480 V solar PV inverter during a fault are shown below.



4.3.6. Impact of Faults on DERs

- **Example 4.14 (Cont.)**: The fault occurs on one phase (thick blue curve) at 0.0802 seconds, as marked by the first vertical dashed line.

- It immediately creates a *sudden drop in voltage* on the faulted phase.

- The fault also causes a surge in current at the PV unit, which quickly reaches as high as 140% of the pre-fault current.

- This ultimately causes the *inverter's protection system* to act.

4.3.6. Impact of Faults on DERs

- **Example 4.14 (Cont.)**: The inverter stops gating and abruptly cuts off current at all three phases at around 0.1341 seconds, as marked by the second vertical dashed line. At this point, the PV unit *trips off-line*.

- The *time to disconnect* is about 54 msec.

  - Also known as the *trip time* or *run-on time* [230, 231].

- The fault is later cleared after a few cycles, *yet the PV unit stays disconnected for the next three minutes*, not shown here.

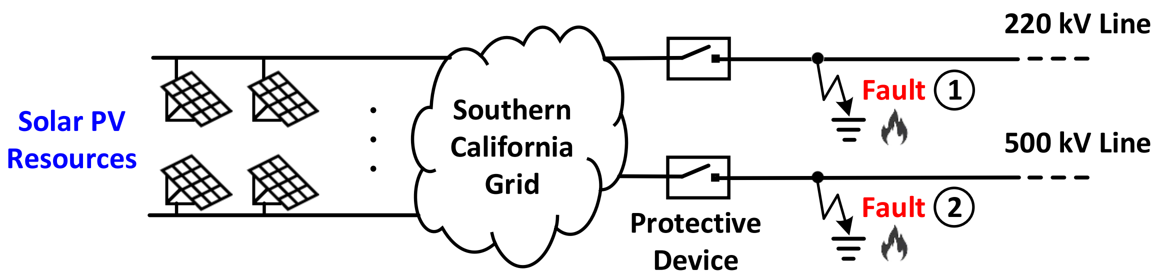
4.3.6. Impact of Faults on DERs

- **Note**: For the scenario in Example 4.14, the inverter was *unable to ride through the fault* so that it can resume normal operation as soon as the fault was cleared. The inverter simply ceased production.

- This can cause severe problems in circumstances where there is a *high penetration of DERs*, as shown in the next example (next slide).

4.3.6. Impact of Faults on DERs

• **Example 4.15**: On October 9, 2017, a *wildfire* caused two transmission line faults in Southern California. The first fault occurred at 12:12 PM on a 220 kV transmission line. The second fault occurred at 12:14 PM on a 500 kV transmission line. Both faults were *cleared normally* by the transmission system's protection devices. Yet they both resulted in drastic reduction in solar PV generation *across the region*.

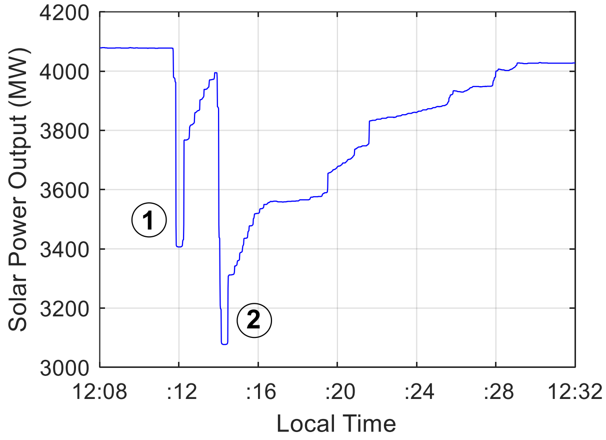


• The first fault resulted in tripping 682 MW of PV resources. The second fault resulted in tripping 937 MW of PV resources.

4.3.6. Impact of Faults on DERs

• **Example 4.15 (Cont.)**: Note that no PV resource was de-energized to clear a fault because the faults had no direct relevance to the PV resources. Instead, these PV resources ceased output as a response to the fault on the system in order to protect their own inverters.

• It took *several minutes* for the PV resources to gradually restore service, as shown in the figure.



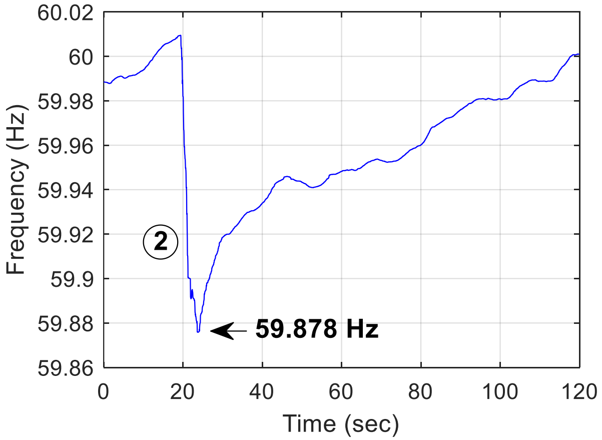
  • Similar to Example 4.14.

4.3.6. Impact of Faults on DERs

• **Example 4.15 (Cont.)**: Losing these PV resources affected the power system frequency; see Section 2.9 in Chapter 2.

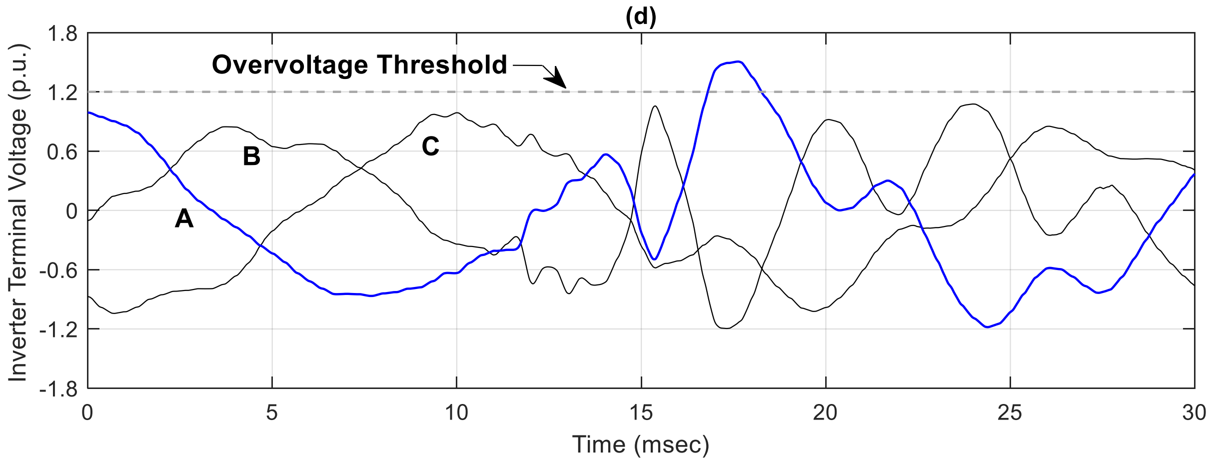
• In particular, the second fault that resulted in losing 900 MW solar PV resources, caused a *frequency excursion* in the Western Interconnection with frequency dropping to 59.878 Hz within 3.3 seconds *after the fault*.

• Frequency gradually recovered to nominal in about 100 seconds.



4.3.6. Impact of Faults on DERs

• **Example 4.15 (Cont.)**: The voltage waveform that was measured at one of the PV inverters is shown below. Notice that the *transient overvoltage* took place on one phase for only a fraction of a cycle; yet it caused the PV inverter to trip because the measured voltage exceeded the overvoltage protective setting for the inverter.



4.3.6. Impact of Faults on DERs

• After studying the above and other similar incidents, it was concluded that a large percentage of the *existing grid-connected inverters* are configured to trip using *instantaneous overvoltage protection*.

  • They do not filter out voltage transients.

• Thus, instantaneous, sub-cycle transient overvoltage may trip the inverter off-line, making these resources susceptible to tripping on transients caused by faults or major switching actions in the bulk power system.

4.3.6. Impact of Faults on DERs

• As another example, it has been observed that some *momentary* system-wide *phase jumps* in the voltage waveforms.

• Such phase jumps that are caused by certain faults can be *mistaken* by inverters as a *severe frequency violation* event.

• This too can cause inverter-based resources to cease production [233].

4.3.6. Impact of Faults on DERs

- The *North American Electric Reliability Corporation* (NERC) recommends setting the voltage protection settings and the frequency protection settings of inverters based on their actual physical equipment limitations, so that, as much as possible, the inverters can *ride through the fault* and continue injecting current to the grid; see [232, 233].
    - Voltage ride through, frequency ride through, etc.

- While Example 4.15 is for the case of solar PV inverters, similar issues on inverter-based *wind generation resources* are reported in [234].

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4.4 Features and Statistical Analysis of Waveform Events

• The examples and the analysis in Section 4.3 showed that a lot can be learned from each event in waveform measurements.

• However, given the enormous number of events that may take place every day, we need a way to translate the waveform measurements during events into *useful information* that can help diagnose issues, discover hidden patterns and unknown correlations, and make recommendations.

• The key to achieving this goal is to define *quantitative features* that can characterize each event and allow conducting *signature evaluation*, event classification, pattern recognition, and statistical analysis.

4.4 Features and Statistical Analysis of Waveform Events

- The basic idea in selecting the features is the same as what we discussed in Section 3.7.2 in Chapter 3 in the context of phasor measurements.

- However, there are also some quantitative features that are somewhat *specific* to waveform measurements and the analysis of waveform events.

- In this section, we discuss several of these quantitative features.

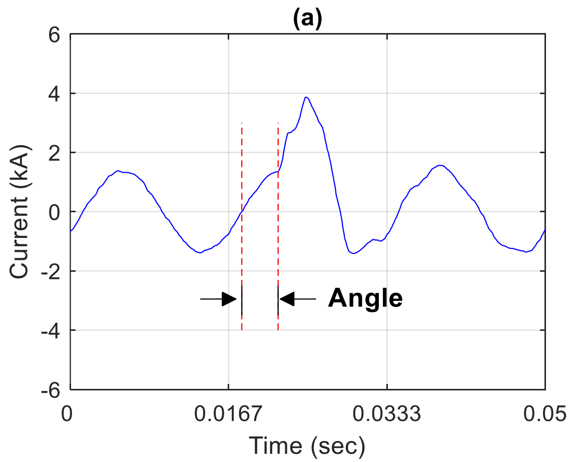
- Some of them are *generic* and can be defined for almost any event in waveform measurements, regardless of the exact type of the event.

- Some are defined only for certain types of events, such as *certain faults*.

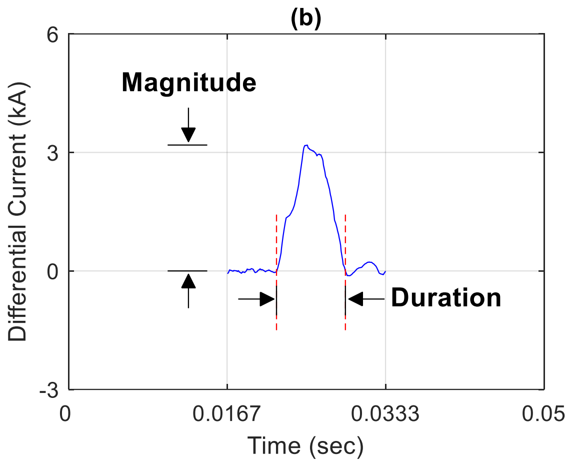
4.4.1. Angle, Magnitude, and Duration

• These basic features can be obtained for most events.

• An example for these three features for the case of a current waveform measurement during a self-clearing fault is shown below.



Original waveform



Differential waveform

4.4.1. Angle, Magnitude, and Duration

- The angle of the event is the *angular difference* between the moment when the event starts and the moment of the most recent zero-crossing point prior the event. The zero-crossing point serves as a reference point.

- For the event on Slide 110:

  - The angle is $82°$
  - The magnitude is 3.187 kA,
  - The duration is 7.25 msec; which is is *less than half a cycle*.

4.4.1. Angle, Magnitude, and Duration

- The angles for certain events *are* often at certain values or within certain ranges, or they *have to be* at certain values or within certain ranges.

- In Example 4.13, energizing the capacitor should happen at or near voltage zero (zero-crossing point) for the purpose of synchronous closing.

    - Thus, we can measure the switching angle, relative to the moment when the voltage is zero, *over several days* to evaluate the operation of the synchronous closing control mechanism.

    - If the percentage of the switching event angles that *fall outside of a given range*, such as $[-45°, 45°]$, exceeds a certain threshold, then we may suspect that the performance of the synchronous closing is poor and that the switch controller must be reprogrammed [221].

4.4.1. Angle, Magnitude, and Duration

• Even for some events where the angle seems arbitrary, a simple statistical analysis may reveal an underlying pattern about the event angle which may help us with identifying the root cause of the event.

• **Example 4.16**: The study in [235] examined the event angle in voltage waveform measurements for 73 faults in *overhead power lines*.

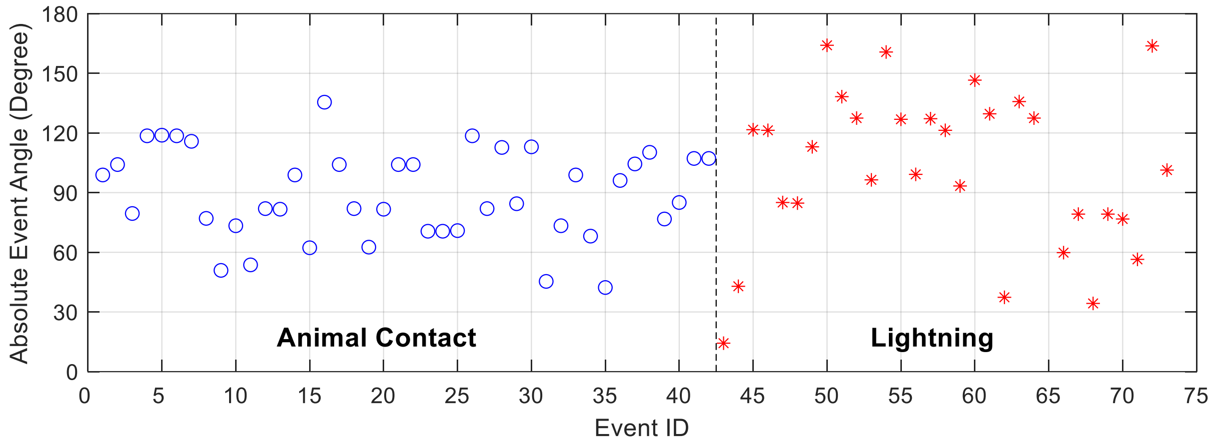
The cause for each fault was already known from the utility records.

The first 42 events were caused by *animal contact*.

The other 31 events were caused by *lightning*.

4.4.1. Angle, Magnitude, and Duration

• **Example 4.16 (Cont.)**: The absolute value of the event angles that are extracted for these 73 events are shown below.



• Most of the events that are caused by animal contact have an absolute angle between 60° and 120°. That means these events almost always occurred around the *positive or negative peaks* of the voltage waveform.

4.4.1. Angle, Magnitude, and Duration

- **Example 4.16 (Cont.)**: There can be an explanation for this observation.

- When the voltage is at its absolute peak, the voltage gradient between the animal and the overhead power line is at its maximum. Conversely, we do not see any such pattern for the events that are caused by lightning.

- Based on the statistical observations on Slide 114, we may conclude that if the angle for an event does not fall within the range [60°, 120°], then it is *unlikely* that the fault was caused by an *animal contact* [235].

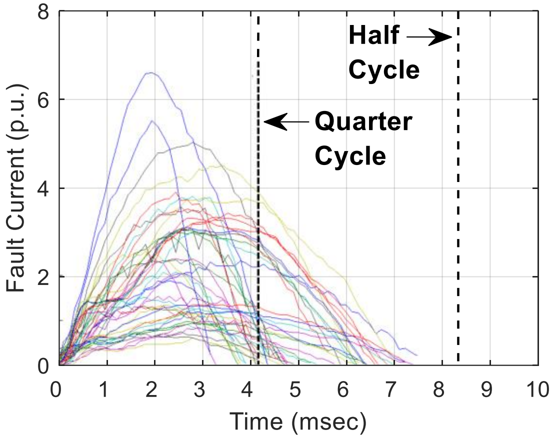
    - But we *cannot* necessarily assume that it is caused by lightning.

4.4.1. Angle, Magnitude, and Duration

• Magnitude and duration of events in waveform measurements can also be used to characterize the events and identify their root causes.

• **Example 4.17**: Consider the sub-cycle blips for over 30 self-clearing single-phase faults in underground cables.

• The curves in this figure are derived by obtaining the differential current waveform during each fault.

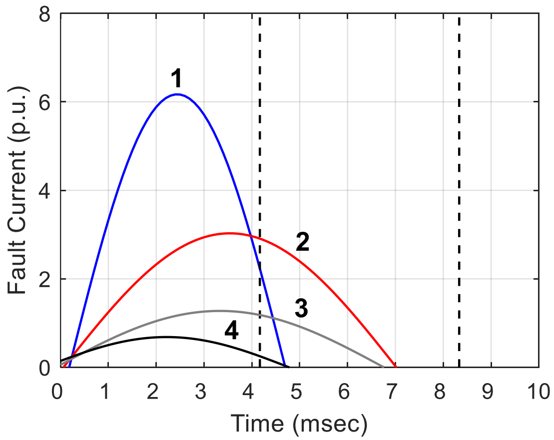


4.4.1. Angle, Magnitude, and Duration

• **Example 4.17 (Cont.)**: Four generic equations can be used to represent all these sub-cycle faults [217]:

$$\begin{aligned}
&1: \quad i_f(t) = 6.17\sin(695.4t - 0.126), && 0 \le t \le 0.0047 \text{ sec},\\
&2: \quad i_f(t) = 3.029\sin(451.37t - 0.02726), && 0 \le t \le 0.0071 \text{ sec},\\
&3: \quad i_f(t) = 1.275\sin(458.036t + 0.04495), && 0 \le t \le 0.0068 \text{ sec},\\
&4: \quad i_f(t) = 0.6846\sin(612.708t + 0.213), && 0 \le t \le 0.0048 \text{ sec}.
\end{aligned}$$

• These four equations are plotted and labeled in the figure.



4.4.1. Angle, Magnitude, and Duration

- **Example 4.17 (Cont.)**: These four classes can be labeled as:

  (1) very high magnitude with a duration of about 1/4 of a cycle;
  (2) high magnitude with a duration of about 1/2 of a cycle;
  (3) small magnitude with a duration of about 1/2 of a cycle;
  (4) small magnitude with a duration of about 1/4 of a cycle.

These labels can be used to determine the cause of the fault.

4.4.1. Angle, Magnitude, and Duration

• **Example 4.17 (Cont.)**: For instance, faults with high magnitude but short duration, under label 1, may be the result of *moisture* entering the cable splice; which means the cable failure is likely in its early stage.

• Conversely, faults with long duration but small magnitude, under label 3, may be caused by *insulation breakdown*; which means the cable failure is perhaps in the mid stage, moving toward a more sustained fault.

4.4.2. Number of Affected Phases

• An event in waveform measurements may affect 1 phase (A, B, or C), 2 phases (A and B, A and C, or B and C), or all 3 phases (A and B and C).

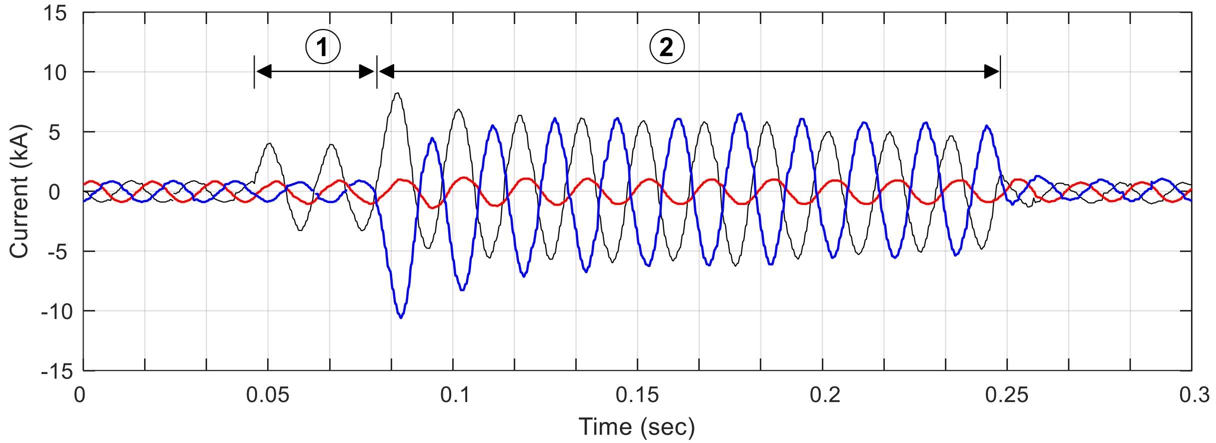
• For example, most *ground faults* occur on only one phase.

• But most major *switching events* take place on all three phases.

• Accordingly, the number of affected phases can be used as another feature for the analysis and *identification of events*.

4.4.2. Number of Affected Phases

• Some events may begin as single-phase but evolve into other phases:



• This fault is *initially single-phase*, during the period that is marked as ①. It then (after about two cycles) evolves into a second phase, during the period that is marked as ②, before it is cleared by a protective device.

• Such evolving behavior by itself is a feature of the fault.

4.4.3. Transient Oscillations

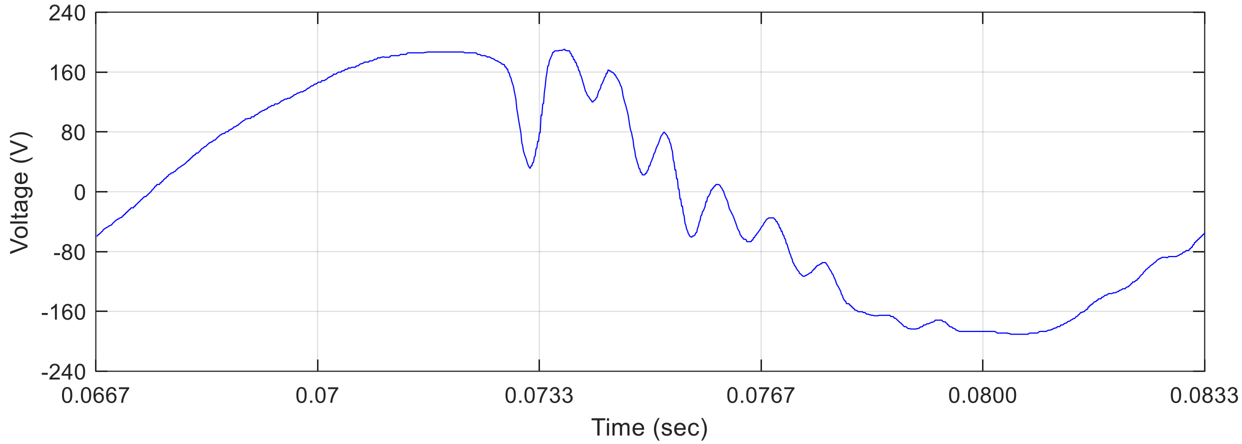
• Many events in power systems create transient oscillations in voltage waveforms and/or current waveforms. The duration of transient oscillations may vary from a few microseconds to several milliseconds.

• Transient oscillations in waveform measurements are described by their *magnitude*, *duration*, and *dominant frequency*.

• The frequency of oscillations in waveform measurements can be obtained by using *modal analysis*; see Section 2.6.3 in Chapter 2.

4.4.3. Transient Oscillations

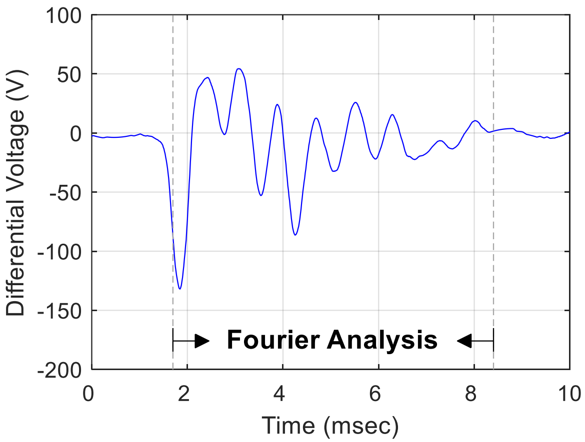
- **Example 4.18**: Consider the ringing event in Example 4.5 (Slide 40):

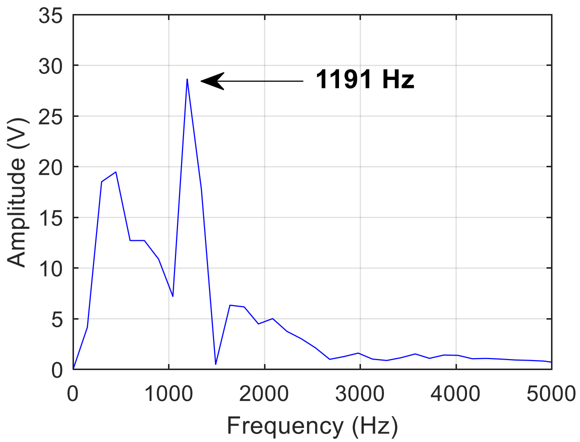


- We want to obtain the *frequency* of these transient oscillations.

4.4.3. Transient Oscillations

• **Example 4.18 (Cont.)**: First, we obtain the differential voltage waveform corresponding to this event, as shown on the left-hand-side below:





• Once we apply Fourier analysis to the waveform between the two vertical dashed lines, the frequency spectrum is obtained as shown above on the right-hand-side. The *dominant frequency* is 1191 Hz.

4.4.3. Transient Oscillations

- The frequencies for waveform transient oscillations are classified as:
  - Low Frequency: Below 5 kHz;
  - Medium Frequency: Between 5 kHz and 500 kHz;
  - High Frequency: Above 500 kHz.

4.4.3. Transient Oscillations

• *Low-frequency* transient oscillations in waveforms take place frequently in sub-transmission and distribution systems.

• They are caused by different types of events.

• For instance, the transient oscillations during the capacitor switching event in Example 4.13 had a dominant frequency of 300 Hz, and the transient oscillations during the fault-induced capacitor ringing event in Example 4.18 had a dominant frequency of 1.2 kHz.

• Oscillatory transients with dominant frequencies less than 300 Hz are often associated with ferroresonance and transformer energization [237].

4.4.3. Transient Oscillations

- *Medium-frequency* transient oscillations in waveforms take place in certain events, such as back-to-back capacitor energization.

- This happens when a capacitor bank is energized in close electrical proximity to another capacitor bank that is in service.

- Another cause for these transient oscillations is cable switching.

4.4.3. Transient Oscillations

• High-frequency transient oscillations are often the result of a local response of an apparatus to an impulsive transient disturbance in the system.

• Note that in order to capture high-frequency transient oscillations, the waveform sensor must have a *very high reporting rate*.

• For instance, to capture the transient oscillations with a frequency of 500 kHz, the reporting rate of the waveform sensor must be at least 1 MHz.

• See Section 2.3 in Chapter 2 for more discussions on reporting rates and sampling rates. It is common for waveform sensors to have a reporting rate that is equal to their sampling rate, i.e., they report all samples.

4.4.4. Transient Impulses

- An impulsive transient is a sudden change in the waveform of voltage, current, or both, that is typically unidirectional in polarity.

- The most common cause of impulsive transients is lightning (Slide 50).

- However, certain faults may also create transient impulses.

- For example, the four transient impulses that we saw on Slide 79 were due to a fault in the termination point of an underground cable.

    - Notice that they appeared only in the voltage waveform and only at the start of the event; three of the four transient impulses on Slide 79 had negative polarity, and one had positive polarity.

4.4.4. Transient Impulses

- Transient impulses are normally characterized by their:
  - Rise time
  - Decay time.
- For example, when an impulsive transient in a voltage waveform is described as having a 1.2/50 waveshape, then 1.2 expresses a measure of the rise time of the impulse in microseconds and 50 expresses a measure of the decay time of the impulse in microseconds [237].

4.4.5. Fault-Specific Features

• Some features in waveform measurements are specific to certain faults.

• For example, recall from Section 4.3.3 that failures in transformer tap changers may cause *momentary zero current* on a faulted phase.

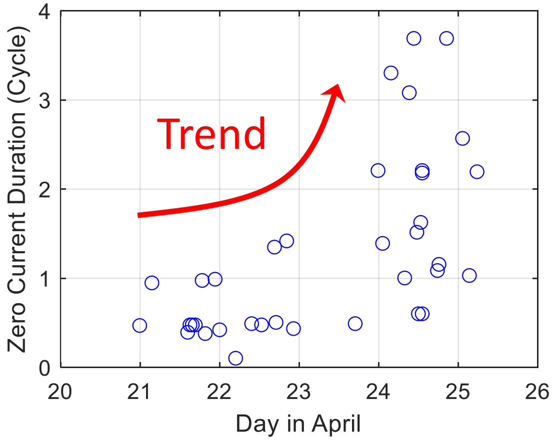
  • At its early stages, this type of fault may occur only occasionally and may last for only a fraction of a cycle.

  • However, over time, the zero-current incidents may take place more frequently and may last longer, ultimately leading to a major failure. Therefore, we may evaluate the *trend* in the characteristics of the zero-current incidents in order to *predict the fault*.

4.4.5. Fault-Specific Features

- **Example 4.19**: In a period of one week before a transformer was taken out of service for repair, about 40 zero-current events were detected, all on the same phase. The duration of these zero-current disturbances during this period are shown below.

- We can see that the duration was *initially* at the *sub-cycle* level during the first two days; however, it *subsequently* increased to *several cycles*.



4.4.5. Fault-Specific Features

- **Example 4.19 (Cont.)**: On the day before the transformer was taken out for repair, half of the zero-current events lasted more than two cycles.

- The trend in the duration of the zero-crossing events can be used as an *indication* that the tap changer is likely to fail in the *near future*.

- Note that, the zero-crossing event in this example is a “fault-specific” feature; because it happens for the specific conditions of this fault.

4.4.5. Fault-Specific Features

- Not all incipient failures in transformer tap changers create zero-current events. However, there is an alternative feature that we can check to potentially predict tap changer failure.

    - An example is given on the next slide.

- It is called the *long-term flicker severity*, denoted by P_{lt}, which is an index to evaluate the severity of flicker in voltage waveforms.

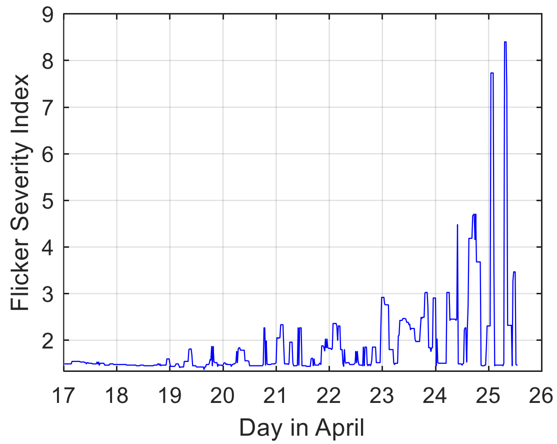
- It is obtained by taking the average of another index, the *short-term flicker severity*, denoted by P_{st}, over intervals of two hours.

- This latter index itself is obtained by conducting a statistical analysis of flicker harmonics in the voltage waveform; see [238, 239].

4.4.5. Fault-Specific Features

- **Example 4.20**: Again, consider the transformer failure in Example 4.19. Figure below shows P_{lt} on the faulted phase voltage during the same week as in Example 4.19, plus a few days earlier.

- At about two days before the first zero-current event occurs, we start seeing some minor abnormalities in the voltage flicker severity. These abnormalities *grow drastically* over the next few days.



- Similar trends are reported in other case studies of transformer tap changer failures; e.g., see [220, 236].

4.4.5. Fault-Specific Features

• Another feature that can be measured during faults is *fault impedance*.

• It can be obtained from the faulted phase voltage waveform, and *either* the faulted phase current waveform *or* the neutral current waveform.

• There are advantages in using the neutral current waveform, if it is available, because it does not contain the load current; therefore, it can provide a better estimation of the fault impedance.

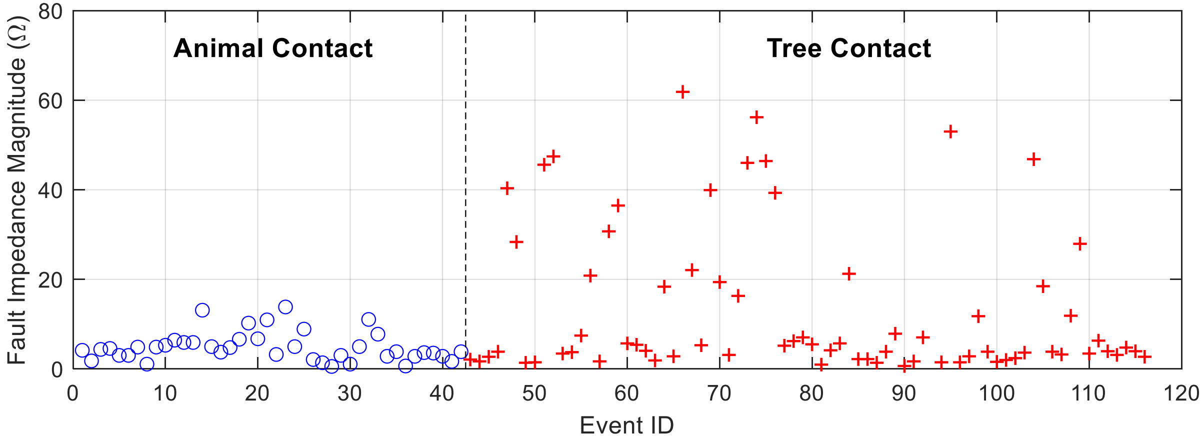
• We may obtain the fault impedance as follows:

$$Z_{\text{fault}} = \frac{V\angle\theta}{I_n\angle\phi_n}$$

4.4.5. Fault-Specific Features

- On Slide 136, $V\angle\theta$ denotes the phasor estimation of the *fundamental component* of the faulted phase voltage, and $I_n\angle\varphi_n$ denotes the phasor estimation of the *fundamental component* of neutral current.

- **Example 4.21**: Figure below shows the measured fault impedance for 116 recorded faults in *overhead power lines* [235].



4.4.5. Fault-Specific Features

- **Example 4.21 (Cont.)**: The first 42 events were caused by *animal contact*. The other 74 events were caused by *tree contact*.

- We can see in the figure on Slide 137 that the fault impedance during animal contacts were always *below* 20 Ω.

- Conversely, the fault impedance during tree contacts were *above* 20 Ω in about one quarter of such events.

- Therefore, we can conclude that if the fault impedance is above 20 Ω, then it is *very unlikely* that the fault was caused by an animal contact.

4.4.6. Changes in Steady-State Characteristics

• Certain events in may create changes in the steady-state characteristics of the waveform. Here, we compare the steady-state characteristics *before* and *after* the event.

• For instance, we saw in Example 4.13 that energizing the capacitor significantly changed the phase angle difference between the voltage waveform and the current waveform.

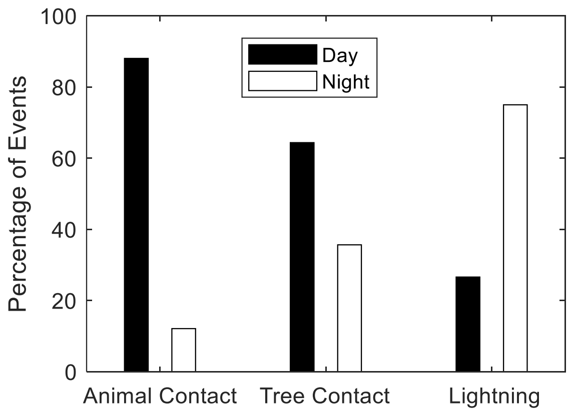
• As another example, one may examine whether there is a considerable increase or a considerable decrease in the strengths of harmonics and the THD value (see Slide 17) in the current or voltage waveform measurements *before* and *after* the event.

4.4.7. Time, Season, and Location

• The *time-stamp* of the event can sometimes be very informative.

• For example, figure below shows the percentage of overhead line faults of different causes that occurred *during the day versus during the night*.

• The faults that are caused by animal contact are much more likely to happen during the day.



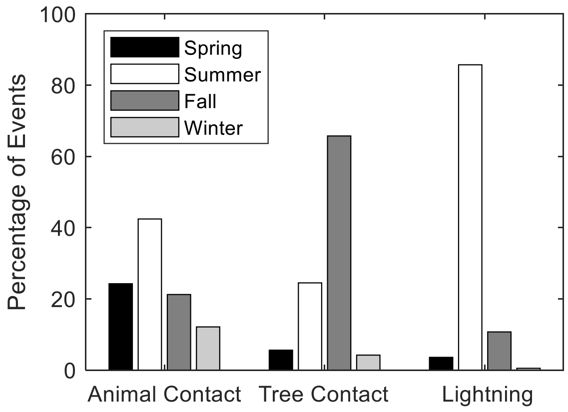
• Combine this with what we learned about the *angle* of such faults on Slide 113, and about the *impedance* of such faults on Slide 137, and we already have several quantitative features to *statistically characterize* this type of fault.

4.4.7. Time, Season, and Location

• Some events are highly *seasonal*.

• For example, figure below shows the percentage of overhead line faults of different causes that occurred during spring, summer, fall, and winter.

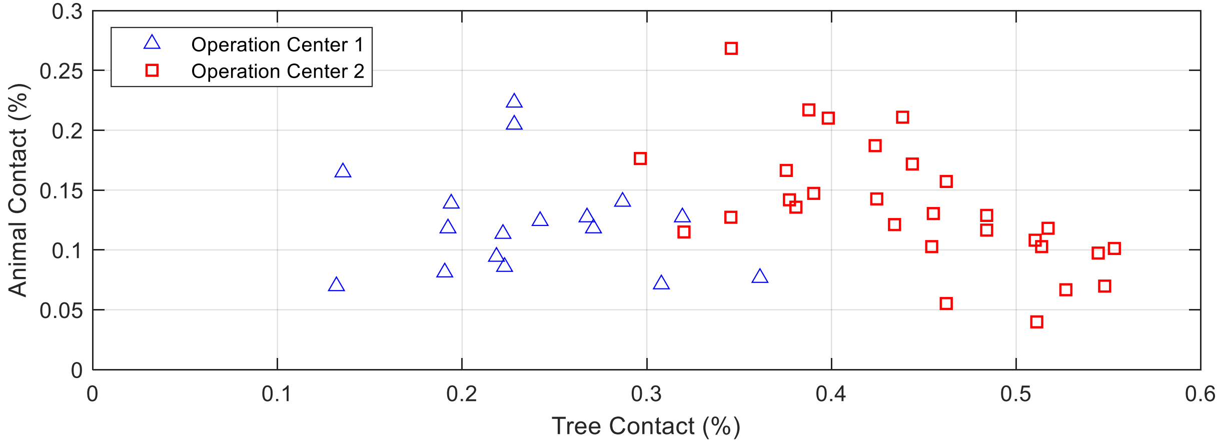
• The faults that are caused by lightning are much more likely to happen in summer, 86% versus 14% in any other season.



• Such seasonal correlation can highly depend on geographical location.

4.4.7. Time, Season, and Location

- Figure below shows the percentage of all faults that are caused by *animal contact* versus the percentage of all faults that are caused by *tree contact* across the substations of two neighboring operation centers in North Carolina in the United States over a period of five years.



4.4.7. Time, Season, and Location

• On Slide 142, the substations of Operation Center 1 are between 300 and 400 miles away from the substations of Operation Center 2.

• We can see (on Slide 142) that the two operation centers experience generally similar percentages of faults that are caused by *animal contact*.

• However, the percentages of the faults that are caused by *tree contact* are much higher across the substations of Operation Center 2.

• Better *vegetation management* might be needed in Operation Center 2.

  • See Slide 83 for another indicator for vegetation management.

4.4.8. Other Features

• There may exist many other types of quantitative factors that can be used to characterize certain types of events in waveform measurements.

• One example is the *weather condition*, i.e., whether the event happens during clear sky, cloudy sky, rain, thunderstorm, wind, snow, ice, or heat.

• Another example is the *loading condition*, such as whether the event happens *during peak-load hours* (of the feeder or the overall system).

4.4.8. Other Features

• **Features from Other Types of Sensors**: Correlation between waveform sensors with some other sensors, *such as equipment sensors*, could also be used as quantitative features to evaluate certain waveform events.

• For instance, incipient failures in transformer tap changers may show strong *correlations* with the measurements at equipment sensors that monitor the *chemicals and temperature* of transformers.

• We will discuss these and other types of equipment sensors and measurements in Section 7.1 in Chapter 7.

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4.5 Harmonic Synchrophasors

- From the equation on Slide 12, a voltage or current waveform with steady-state distortion can be represented in frequency-domain using its fundamental phasor $X_1\angle\phi_1$together with the following *harmonic phasors*:

$$X_2\angle\phi_2,\ \ X_3\angle\phi_3,\ \ X_4\angle\phi_4,\ \ \ldots.$$

- The frequencies for the above harmonic phasors are $2f$, $3f$, $4f$, etc.

- If the harmonic phasors are time-stamped:

    - Then they become *harmonic synchrophasors*.

4.5 Harmonic Synchrophasors

• The instrument to measure harmonic synchrophasors is called the *Harmonic Phasor Measurement Unit* (H-PMU).

• Unlike PMUs, H-PMUs are still a developing concept (as of 2022) and they have not yet been widely adopted by the power industry.

• H-PMUs are not intended to stream the phasors for all harmonics.

• Providing such a heavy load of data is not easy. It is not necessary either. If we really want to *fully reconstruct* the voltage or current waveforms from all harmonics, then we should use other sensors that provide synchronized waveform measurements in *time-domain*; see Section 4.6.1.

4.5 Harmonic Synchrophasors

- In practice, we may want an H-PMU to stream the harmonic synchrophasors for only a few harmonic orders.

- Suppose an H-PMU can stream three harmonic synchrophasors.

- Here are *two options* for choosing the harmonic orders to be streamed:

  1. The *3rd* harmonic; the *5th* harmonic; and the *7th* harmonic.

  2. The *most dominant* harmonic; the *second most dominant* harmonic; and the *third most dominant* harmonic.

4.5 Harmonic Synchrophasors

- In the first option on Slide 149, we provide a steady stream of three harmonic phasors that are *often* used in most applications.

- In the second option on Slide 149, we may switch across different harmonics *depending* on which harmonics are most dominant at any time.

- Of course, under the second option, the H-PMU should indicate the harmonic orders that it is streaming at any given time.

- The first option is likely more appropriate for steady-state analysis, such as in harmonic state estimation. The second option is likely more appropriate for the analysis of events and faults.

4.5 Harmonic Synchrophasors

- It should be noted that some of the concepts that we learned in Chapter 3 for PMUs are also applicable to H-PMUs, such as:
    - wrapping around the phase angle
    - the impact of ROCOF on measuring phase angle,
    - the definition of TVE.

4.5.1. Harmonic State Estimation

• The problem formulation for harmonic state estimation is generally similar to that of the fundamental state estimation in Section 3.8 in Chapter 3.

• One key difference is in the choice of the states of the system.

• While the system states in fundamental state estimation are often the magnitude and phase of the nodal voltage phasors at each bus, in harmonic state estimation, the states may rather consist of the magnitude and phase angle of the current injection phasors at each bus, or at each candidate bus that could be a source of harmonics.

• This is because one of the main purposes of harmonic state estimation is to *identify the sources of major harmonics* in the system.

4.5 Harmonic Synchrophasors

4.5.1. Harmonic State Estimation

• As for the measurements, they may include both nodal harmonic voltage phasors and branch harmonic current phasors.

• Harmonic state estimation must be done separately for *each harmonic order*. For example, if our goal is to identify the sources of the 3rd, the 5th, and the 7th harmonics, then we should formulate and solve three separate harmonic state estimation problems, one for each harmonic order.

• **Basic Formulation**: For each harmonic order h, let $\mathbf{z}\{h\}$ denote the vector of all nodal voltage and branch current harmonic phasor measurements. Let $\mathbf{x}\{h\}$ denote the vector of system states, i.e., the harmonic phasors for harmonic current injection at certain candidate buses (or all buses).

4.5 Harmonic Synchrophasors

4.5.1. Harmonic State Estimation

• Similar to problem formulation in Chapter 3, we can express the relationship between the measurements and the state variables as follows:

$$\mathbf{z}\{h\} = \mathbf{A}\{h\}\mathbf{x}\{h\} + \boldsymbol{\epsilon}\{h\},$$

where

$\mathbf{A}\{h\}$ is a matrix that relates $\mathbf{z}\{h\}$ and $\mathbf{x}\{h\}$

$\boldsymbol{\epsilon}\{h\}$ is the vector of measurement errors.

• The size and entries of matrix $\mathbf{A}\{h\}$ depend on the network configuration, and the choices of the measurements and states.

4.5 Harmonic Synchrophasors

4.5.1. Harmonic State Estimation

- The harmonic state estimation problem at harmonic order h:

$$\min_{\mathbf{x}\{h\}} \ \|\mathbf{z}\{h\} - \mathbf{A}\{h\}\mathbf{x}\{h\}\|_2 \,.$$

- If enough harmonic synchrophasor measurements are available, then we can solve the above problem by using the standard LS method:

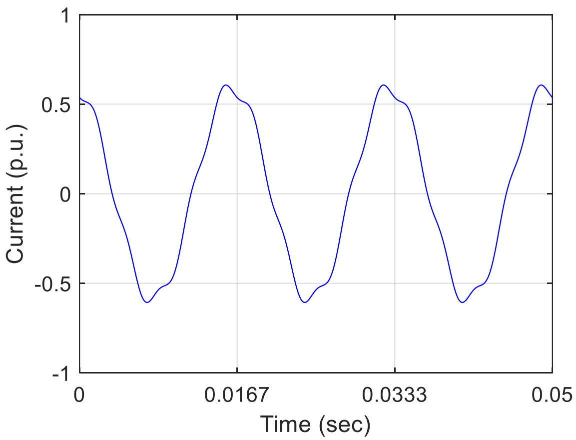
$$\mathbf{x}\{h\} = (\mathbf{A}\{h\}^T \mathbf{A}\{h\})^{-1} \mathbf{A}\{h\}^T \mathbf{z}\{h\}.$$

4.5 Harmonic Synchrophasors

4.5.1. Harmonic State Estimation

• **Example 4.22**: Consider the 4-bus transmission network in Example 3.20 in Chapter 3. Suppose the steady-state current waveform on the transmission line between bus 2 and bus 4 is measured, as shown below.

• Fourier analysis reveals the presence of a considerable 5th harmonic.

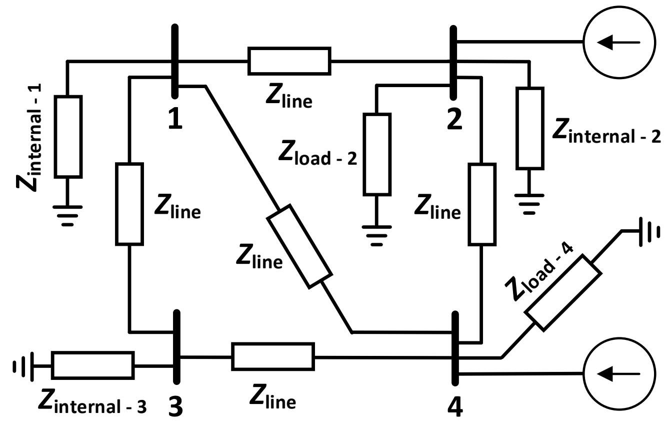


• Suppose the source of the harmonic is unknown. There are two candidate locations, bus 2 and bus 4, which are both load buses. We want to identify the source of the harmonics using state estimation.

4.5.1. Harmonic State Estimation

- **Example 4.22 (Cont.)**: Harmonic state estimation must be done on harmonic order $h = 5$ in order to obtain the source of harmonics. The network model is shown below. In order to do harmonic state estimation, all power plants are represented by their internal impedances.

- In order to do harmonic state estimation, all power plants are represented by their *internal impedances*. Two harmonic current sources are added to the network model at the two candidate harmonic source locations: bus 2 and bus 4.



4.5.1. Harmonic State Estimation

- **Example 4.22 (Cont.)**: All impedances must be represented based on the 5th harmonic. For instance, recall from Example 3.20 in Chapter 3 that the admittance of each transmission line is $0.5 - j10$ p.u. Accordingly, for the network model under the *5th harmonic*, we have:

$$Z_{\text{line}} = 1/\left(0.5 - j10 \times 5\right) = 0.0002 + j0.02 \text{ p.u.}$$

- The internal impedance at each of the three power plants is:

$$Z_{\text{internal}} = j0.25 \times 5 = 1.25 \text{ p.u.}$$

- The load impedances at load buses 2 and 4 are:

$$Z_{\text{load},2} = 0.5710 + j0.1903 \times 5 = 0.5710 + j0.9515 \text{ p.u.}$$
$$Z_{\text{load},4} = 0.2239 + j0.0564 \times 5 = 0.2239 + j0.2820 \text{ p.u.}$$

4.5.1. Harmonic State Estimation

- **Example 4.22 (Cont.)**: The state variables are the two unknown injected harmonic current phasors at buses 2 and 4; thus, vector $x\{5\}$ is 2×1.
- Harmonic synchro-phasors are measured using H-PMUs:

Bus #	True Voltage (p.u.)	Measured Voltage (p.u.)
1	$0.034352\angle 67.5606^\circ$	–
2	$0.034154\angle 67.3670^\circ$	–
3	$0.034417\angle 67.6243^\circ$	$0.033539\angle 67.0418^\circ$
4	$0.035034\angle 67.6777^\circ$	$0.034312\angle 66.6236^\circ$
Line #	**True Current (p.u.)**	**Measured Current (p.u.)**
1,2	$0.011465\angle 8.3390^\circ$	$0.011709\angle 8.6784^\circ$
1,3	$0.003802\angle -171.6580^\circ$	–
1,4	$0.034291\angle 164.1274^\circ$	$0.035615\angle 164.3268^\circ$
2,4	$0.044994\angle 170.1260^\circ$	$0.046402\angle 170.3159^\circ$
3,4	$0.030863\angle 161.2316^\circ$	$0.030204\angle 161.8703^\circ$

4.5.1. Harmonic State Estimation

- **Example 4.22 (Cont.)**: Vectors $\mathbf{z}\{5\}$ and $\boldsymbol{\epsilon}\{h\}$ are 6 × 1. The first two rows in vector z{5} correspond to the two harmonic voltage synchro-phasor measurements, and the next four rows in $z\{5\}$ correspond to the four harmonic current synchro-phasor measurements. We have:

$$\mathbf{A} = \begin{bmatrix} 0.0647 + j0.1572 & 0.0655 + j0.1591 \\ 0.0657 + j0.1576 & 0.0665 + j0.1620 \\ -0.3136 + j0.0098 & 0.0567 + j0.0083 \\ 0.0822 + j0.0453 & -0.1649 + j0.0469 \\ 0.3958 + j0.0354 & -0.2216 + j0.0386 \\ -0.0218 + j0.0485 & -0.1461 + j0.0497 \end{bmatrix}$$

4.5.1. Harmonic State Estimation

- **Example 4.22 (Cont.)**: By applying the closed-form formulation on Slide 155, the states of the system at buses 2 and 4 are obtained as

$$0.00331\angle{-173.71^\circ} \quad \text{and} \quad 0.20017\angle{-0.34^\circ}.$$

- The magnitude of the estimated injected current at bus 4 is almost 200 times larger than the magnitude of the estimated injected current at bus 2.

- Therefore, we can conclude that the *source of the harmonic* is at bus 4.

4.5 Harmonic Synchrophasors

4.5.1. Harmonic State Estimation

• **Sparsity**:

• If only a small number of H-PMUs are available, then problem formulation in Slide 155 can be under-determined.

• In particular, if the number of harmonic synchro-phasor measurements is less than the number of candidate buses, then matrix $A\{h\}^T A\{h\}$ can be singular; which leads to unbounded estimation error.

• Even if the number of harmonic synchro-phasor measurements is just enough for this matrix to be theoretically non-singular, it can still be ill-conditioned in case of low redundancy; which can create numerical issues in solving the harmonic state estimation problem.

4.5.1. Harmonic State Estimation

• **Sparsity (Cont.)**:

• However, the good news is that, in practice, there are only a small number of simultaneous large harmonic sources among the candidate buses.

• Therefore, for any harmonic order, the solution space for the harmonic state estimation can be sparse, in particular in power distribution systems.

• As a result, we can use the concept of *sparse recovery* from signal processing, cf. [250], and reformulate problem in Slide 155 as in [251]:

$$\begin{aligned} \min_{\mathbf{x}\{h\}} \quad & \|\mathbf{x}\{h\}\|_0 \\ \text{s.t.} \quad & \|\mathbf{z}\{h\} - \mathbf{A}\{h\}\mathbf{x}\{h\}\|_1 \leq \varepsilon \end{aligned}$$

4.5.1. Harmonic State Estimation

- **Sparsity (Cont.)**:

• In Slide 163, notation $\|\{h\}\|_0$ is the l_0 norm, which equals the number of non-zero entries; and $\|\{h\}\|_1$ is the l_1 norm, which equals the summation of the absolute values of all entries.

• Basically, for the formulation in Slide 163, we seek to select the minimum number of harmonic source locations among all the candidate locations, subject to maintaining a small level of residue in the measurements.

• Details about *sparse recovery* in this problem are available in [154, 251].

4.5 Harmonic Synchrophasors

4.5.2. Topology Identification

• Harmonic synchro-phasors can also be used in *parameter estimation*.

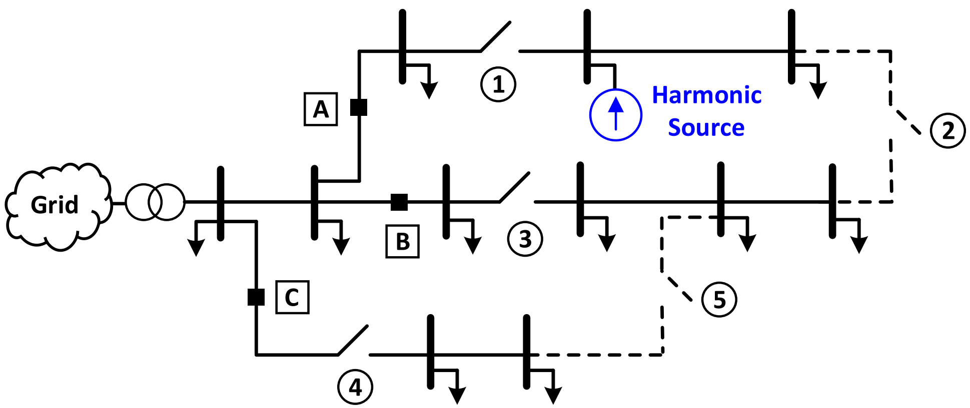
• For example, we may use harmonic synchro-phasors to estimate the status of a switch in order to solve the topology identification problem

• The topology identification problem is defined in Section 3.8.3 (Chapter 3).

• Of course, whether a switch is open or closed is not by itself related to harmonics; however, the *presence* or the *absence* of certain harmonics may help us determine the status of the switches to identify the topology.

4.5.2. Topology Identification

- Consider the following power distribution network:

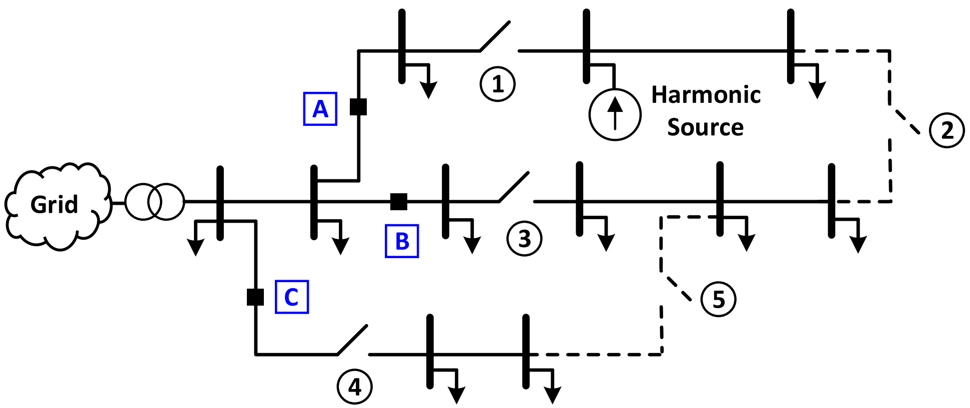


- The network includes 5 switches. Switches ①, ③, and ④ are the *normally closed* switches. Switches ② and ⑤ are the *normally open* switches.

- There is a single source of harmonic on the top lateral.

4.5.2. Topology Identification

- Consider the following power distribution network:



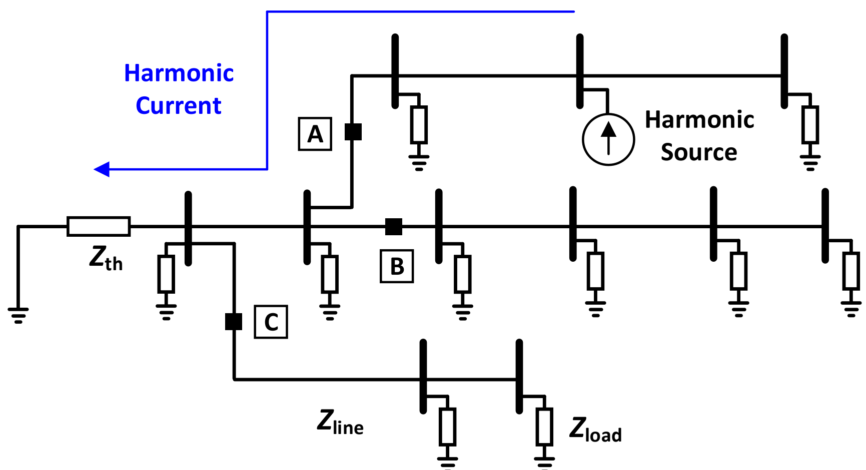
- There are 3 H-PMUs at the beginning of each lateral, denoted by A, B, C.

- They measure the harmonic current synchro-phasors on the three laterals.

4.5 Harmonic Synchrophasors

4.5.2. Topology Identification

• Suppose switches ①, ③, and ④ are *closed* and switches ② and ⑤ are *open*. In that case, the network model at the harmonic is obtained as shown below, where the only source is the harmonic source.



• All other sources are removed. This includes the voltage source in the *Thevenin equivalent* circuit model of the distribution substation. All loads are modeled by their impedance. We can make the practical assumption that the substation. All loads are modeled by their impedance. The impedance of the distribution lines is assumed to be negligible. All impedances are adjusted based on the order of the harmonic, i.e., similar to Section 4.5.1.

4.5 Harmonic Synchrophasors

4.5.2. Topology Identification

- In practice, the magnitude of Z_{th} is much less than the magnitude of Z_{load}.

- Therefore, the harmonic current almost entirely flows through the substation and not through the loads; see the blue arrow on Slide 168.

    - As a result, only H-PMU A may measure a harmonic current phasor with a considerable magnitude.

- The above analysis can be used to identify the status of switches.

    - The generalization of the idea is shown on the next slide.

4.5.2. Topology Identification

- If considerable harmonic current is reported by H-PMU A but not by H-PMUs B and C, then we switch ① is closed and switch ② is open.

- If considerable harmonic current is reported by H-PMU C but not by H-PMUs A and B, then switches ① and ③ are open and switches ②, ④, and ⑤ are closed.

- Note: In this analysis, we assume that all network topologies are radial; that means there is no loop in the distribution network; see [252].

4.5 Harmonic Synchrophasors

4.5.2. Topology Identification

• **Probing Interpretation**: The harmonic component that is generated by the harmonic source in the analysis on Slides 166 – 170, is a *probing signal* that is monitored by the three H-PMUs to identify the network topology.

• Such a harmonic source could be simply a nonlinear load that already exists in the system at a known location. However, if needed, the harmonic source could also be *intentionally* positioned in the network such that it can help with identifying the network topology.

• In this latter setup, the harmonic could be generated only when the operator is unsure about the network topology.

• We will discuss the concept of *probing* in greater details in Chapter 6.

4.5.3. Differential Harmonic Synchrophasors

• The concepts of phasor differential and differential synchrophasors that we covered in Section 3.5 in Chapter 3 can also be defined for harmonic synchrophasors. PD corresponding to harmonic order h is obtained as:

$$\Delta X_h = X_{h,\mathrm{before}} - X_{h,\mathrm{after}},$$

• where $X_{h,\mathrm{before}}$ and $X_{h,\mathrm{after}}$ denote the harmonic phasor measurements of order h that are obtained *before* and *after* the event, respectively.

• Once such PDs are obtained at multiple H-PMUs, they can be time synchronized in order to create *differential harmonic synchrophasors* of harmonic order h. Differential harmonic synchrophasors capture how an event may *create*, *eliminate*, or *change* the magnitude or phase angle of steady-state waveform distortions in voltage or current.

<u>4.5.3. Differential Harmonic Synchrophasors</u>

• Similar to differential synchrophasors, we can use differential harmonic synchrophasors to identify the location of an event. This is very useful if the event mainly affects the harmonics, as opposed to the fundamental.

• An example for such event is a *high-impedance fault* (HIF) that can be caused, for instance, by a tree with a power line; see Section 4.4.5.

• An HIF often creates a considerable *3rd harmonic* [253].

• Therefore, we may still use the method in Section 3.5.4, but we should apply it to differential harmonic synchrophasors of the 3rd harmonic, instead of the fundamental differential synchrophasors; see [254].

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4.6 Synchronized Waveform Measurements

- Once the measurements from multiple waveform sensors are *time-synchronized*, such as by using GPS as we discussed in Section 3.2 in Chapter 2, they can collectively form *synchronized waveform measurements*, also known as synchro-waveform measurements.

    - The term “synchro-waveform” can be compared with “synchro-phasors” and “harmonic synchro-phasors” that we have seen before.

- Thus, we can extend the concept of PMUs and H-PMUs and introduce a new class of sensors, called *Waveform Measurement Units* (WMUs), which report time-stamped voltage and current waveform measurements [255].

- Unlike the measurements from PMUs and H-PMUs that are in *frequency-domain*, the measurements from WMUs are in *time-domain*.

4.6 Synchronized Waveform Measurements

- **Note**: The measurements from WMUs in *time-domain* during *steady-state* conditions essentially provide the *same level of information* as the measurements from PMUs and H-PMUs in *frequency-domain*.

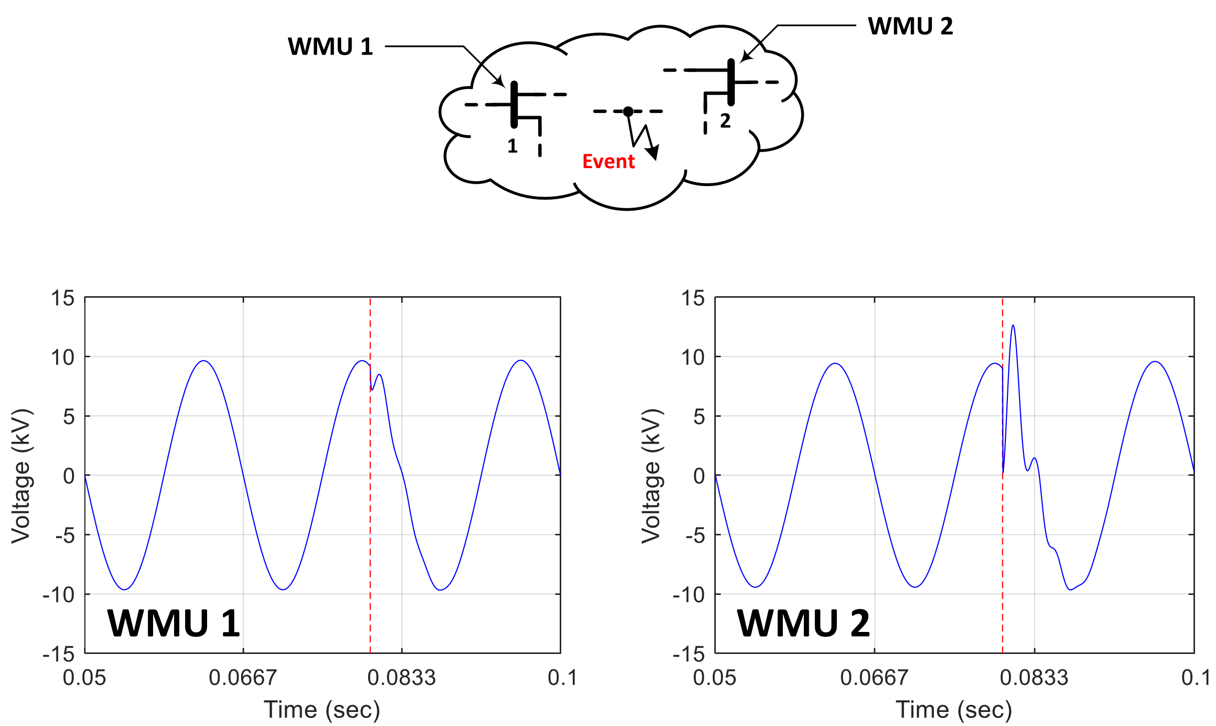
- However, the story is different when it comes to *transient conditions*.

- Since both PMUs and H-PMUs apply Fourier analysis to a window of waveform measurements, they are *inherently incapable* of providing the same level of information about the transient behavior in the voltage and current waveforms that are provided by WMUs in time-domain.

- Therefore, the measurements from WMUs are likely to be most appreciated when they are used to analyze events and *transient conditions*.

4.6 Synchronized Waveform Measurements

- An illustrative example for synchronized waveform measurements:



- WMUs *simultaneously* capture the voltage waveform during an event.

4.6 Synchronized Waveform Measurements

- WMUs are most useful for the simultaneous capture of the events.

- Nevertheless, in the future, it might be valuable for WMUs to provide *continuous streaming* of the synchronized waveform measurements, similar to the continuous streaming of the synchronized phasor measurements that is commonly done by PMUs.

- WMUs that can provide continuous synchro-waveform measurements may be referred to as *Continuous Point-on-Wave (CPoW)* sensors.

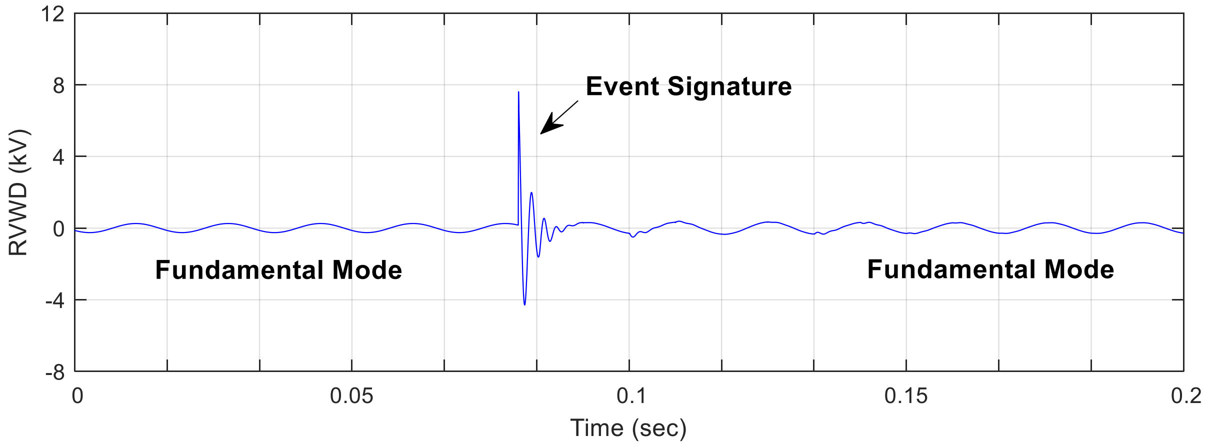
4.6 Synchronized Waveform Measurements

4.6.1. Relative Waveform Difference

- Consider two synchronized voltage waveforms $v_1(t)$ and $v_2(t)$ that are reported by two WMUs. We can define the *Relative Voltage Waveform Difference* (RVWD) for these two synchronized waveform measurements as

$$\mathrm{RVWD}(t) = v_1(t) - v_2(t).$$

- $\mathrm{RVWD}(t)$ itself is a waveform:

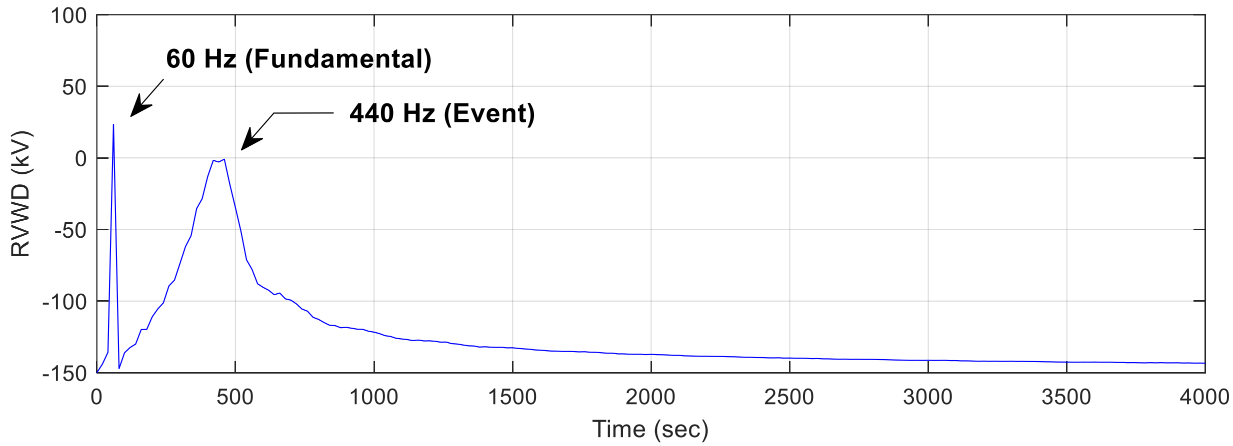


4.6 Synchronized Waveform Measurements

4.6.1. Relative Waveform Difference

- In Slide 179, we can see that the event creates a *major signature* in $\mathrm{RVWD}(t)$. It involves a spike followed by damping oscillations.

- RVWD can also be analyzed in frequency domain:



4.6.1. Relative Waveform Difference

- In Slide 180, two dominant frequencies are identified:
  - At 60 Hz, which is the fundamental frequency,
  - At 440 Hz, which is the frequency of the damping oscillations.
- Both the time-domain signature in Slide 179 and the frequency-domain signature in Slide 180 can be used to *detect* and *characterize* the event.

4.6.1. Relative Waveform Difference

- **Relationship with RPAD**:

- The concept of RVWD is related to the concept of RPAD in Chapter 3.

  - RPAD is a concept in synchro-phasors.

  - Q: Is there any relationship between RVWD and RPAD?

- Let $V_1\angle\theta_1$ and $V_2\angle\theta_2$ denote the phasor representation of the synchronized voltage waveforms $v_1(t)$ and $v_2(t)$ at WMU 1 and WMU 2.

  - We would obtain RPAD from $V_1\angle\theta_1$ and $V_2\angle\theta_2$.

4.6.1. Relative Waveform Difference

- **Relationship with RPAD (Cont.)**:

- Suppose the voltage waveforms are purely sinusoidal at *steady-state*:

$$v_1(t) = \sqrt{2}V_1 \cos(\omega t + \theta_1),$$
$$v_2(t) = \sqrt{2}V_2 \cos(\omega t + \theta_2).$$

- This can be a valid assumption *before* and *after* an event.

- Suppose the voltage is represented in per unit, where $V_1 = V_2 = 1$ p.u.

4.6.1. Relative Waveform Difference

- **Relationship with RPAD (Cont.)**:

- We can derive the following relationship between RVWD and RPAD:

$$
\begin{aligned}
\mathrm{RVWD}(t) &= \sqrt{2}\left[\cos(\omega t + \theta_1) - \cos(\omega t + \theta_2)\right] \\
&= -2\sqrt{2}\sin\left(\frac{\theta_1 - \theta_2}{2}\right)\sin\left(\omega t + \frac{\theta_1 + \theta_2}{2}\right) \\
&\approx -\sqrt{2}\,(\theta_1 - \theta_2)\sin\left(\omega t + \frac{\theta_1 + \theta_2}{2}\right) \\
&= \sqrt{2}\,\mathrm{RPAD}\ \sin\left(\omega t + \frac{\theta_1 + \theta_2}{2}\right).
\end{aligned}
$$

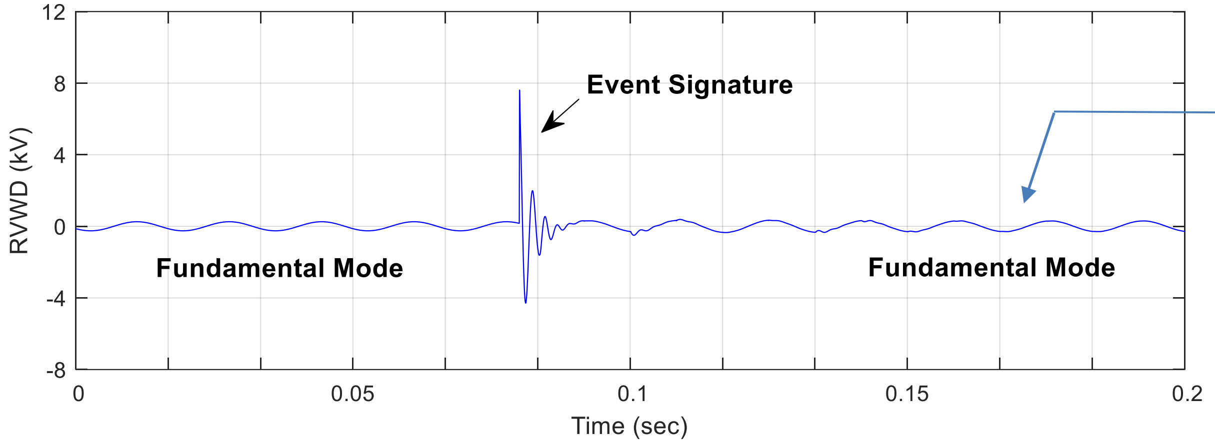
- **Note**: θ_1 and θ_2 must be in *radians* in order for the approximation in the third line to be valid; accordingly, RPAD must also be expressed in *radians*.

4.6 Synchronized Waveform Measurements

4.6.1. Relative Waveform Difference

- **Relationship with RPAD (Cont.)**:

- The expression in Slide 184 can help explain the steady-state sinusoidal oscillations (at fundamental) before and after the event in Slide 179.



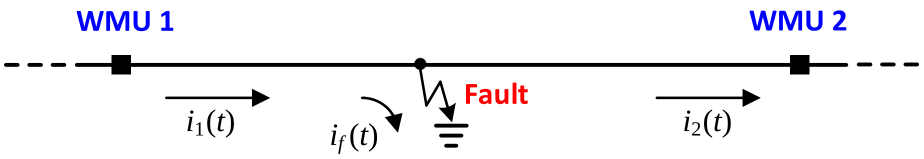
Oscillating at the *fundamental* angular frequency ω.

- The magnitude of such sinusoidal oscillations is $\sqrt{2}\,\mathrm{RPAD}$. Thus, at *steady state*, the RMS value of $\mathrm{RVWD}(t)$ is approximately equal to RPAD.

4.6.1. Relative Waveform Difference

- **Monitoring Transmission Lines**:

- WMUs can be used to monitor long underground cables or overhead lines. The idea is to install one WMU *at each end* of the transmission line:



- Let $i_1(t)$ and $i_2(t)$ denote the synchronized current waveforms that are measured by WMU 1 and WMU 2. We can define the *Relative Current Waveform Difference* (RCWD) for this scenario as:

$$\mathrm{RCWD}(t) = i_1(t) - i_2(t).$$

4.6 Synchronized Waveform Measurements

4.6.1. Relative Waveform Difference

- **Monitoring Transmission Lines (Cont.)**:

- If there is no fault anywhere on the transmission line, then RCWD is *theoretically zero*, i.e., theoretically we have: $\mathrm{RCWD}(t) = 0$.

- In reality, there can be some *small non-zero current* in RCWD due to measurement errors or other minor issues such as *discrete spectral interference* for the case of overhead lines; see Section 4.7.

- Nevertheless, any *significant increase* in the magnitude of RCWD can be seen as an indication for the presence of fault current, which is denoted by $i_f(t)$ in Slide 186; because $\mathrm{RCWD}(t) \approx i_f(t)$. Recall from Section 4.3 that the fault current can be due to various faults or even incipient faults.

4.6 Synchronized Waveform Measurements

4.6.1. Relative Waveform Difference

- **Monitoring Transmission Lines (Cont.)**:

- Note: The application of WMUs in transmission line monitoring is similar to the concept of *differential relays* in power system protection, where time-synchronization between the two measurement points are often achieved directly by using *fiber-optic communications* [257].

4.6 Synchronized Waveform Measurements

4.6.2. Modal Analysis of Synchronized Transient Waveforms

• Measurements from WMUs can also be analyzed in *frequency-domain*.

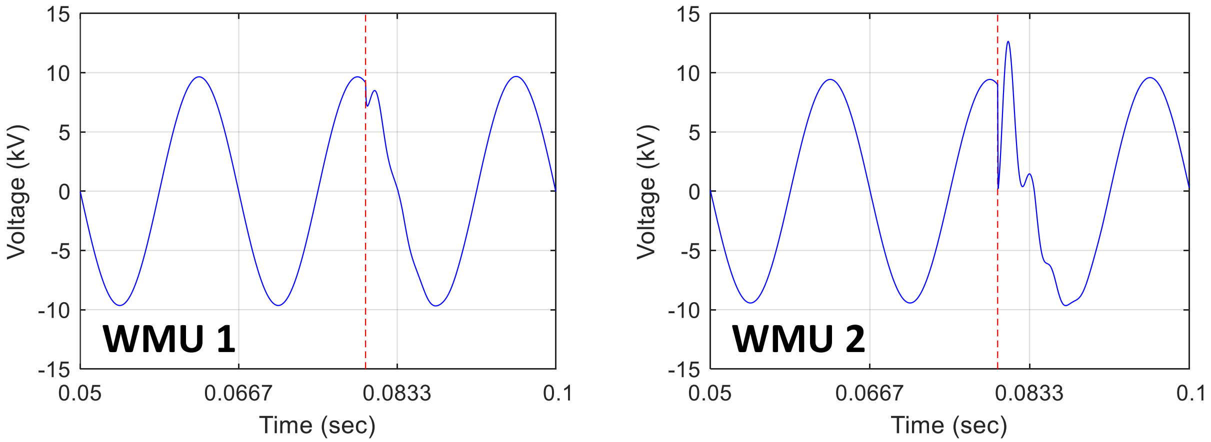
• Of course, if our concern is to examine the steady-state synchronized waveform measurements, then we should use PMUs or H-PMUs.

• However, if our concern is to examine the *transient* behavior, then we can apply the *modal analysis* (see Section 2.6.3 in Chapter 2) to the waveform measurements that are captured by each WMU.

  • An example is shown on the next slide.

4.6.2. Modal Analysis of Synchronized Transient Waveforms

- **Example 4.23**: Again, consider the two synchronized voltage waveform measurements in Slide 177. The moment when the event occurs is marked on both waveforms using vertical dashed lines.



- We can apply the modal analysis to each waveform immediately after the event occurs. **Note**: This requires first detecting the start of the event.

4.6.2. Modal Analysis of Synchronized Transient Waveforms

• **Example 4.23 (Cont.)**: The five most dominant oscillatory modes of the waveform at WMU 1 and WMU 2 are obtained as follows:

WMU 1:

Oscillation Mode	**1**	**2**	**3**	**4**	**5**
Frequency (Hz)	60	355.27	441.91	556.85	792.92
Damping Factor (Hz)	0	−1.98	−1.49	−2.08	−2.44
Amplitude (kV)	4.842	0.325	1.189	0.493	0.153
Phase Angle (°)	17.94	−176.48	151.64	−97.87	−55.75

WMU 2:

Oscillation Mode	**1**	**2**	**3**	**4**	**5**
Frequency (Hz)	60	345.43	434.72	526.47	748.12
Damping Factor (Hz)	0	−1.72	−1.67	−1.90	−2.40
Amplitude (kV)	4.803	0.912	6.615	2.816	0.800
Phase Angle (°)	16.14	173.96	175.94	−38.90	13.88

4.6.2. Modal Analysis of Synchronized Transient Waveforms

- **Example 4.23 (Cont.)**: Both waveform measurements include a dominant fundamental mode, at frequency 60 Hz with no damping.

- Each waveform measurement also includes several damping oscillatory modes. The frequency of the most dominant *damping oscillatory mode* at WMU 1 is 441.91 Hz, and at WMU 2 is 434.72 Hz.

- **Note 1**: The above modal analysis can be used to *identify the location* of the transient event that is captured in the synchro-waveforms; see [256].

- **Note 2**: To obtain the same oscillatory modes in the waveform measurements from WMU 1 and WMU 2, it is recommended to use *multi-signal modal analysis*, instead of individual modal analysis [258].

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4.7 Accuracy in Waveform Measurements

- The basic metrics to evaluate the accuracy of waveform sensors are similar to those that we saw in Section 2.3 in Chapter 2.

- For instance, for the waveform sensor in [259], the accuracy is presented as 0.33% of the *full scale* (FS), where FS is 600 V.

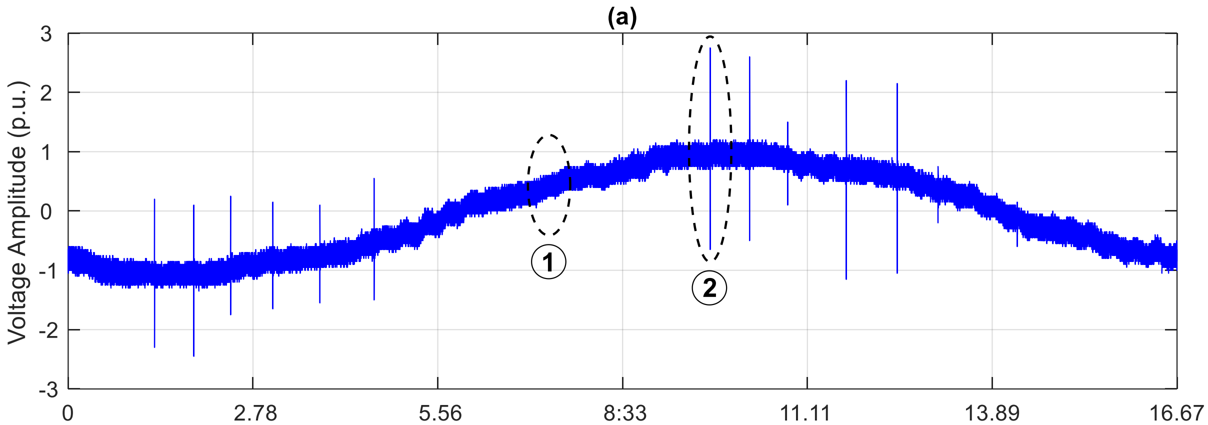
- Accordingly, the accuracy for this sensor is ±1.98 V.

4.7 Accuracy in Waveform Measurements

4.7.1. Impact of Noise and Interference

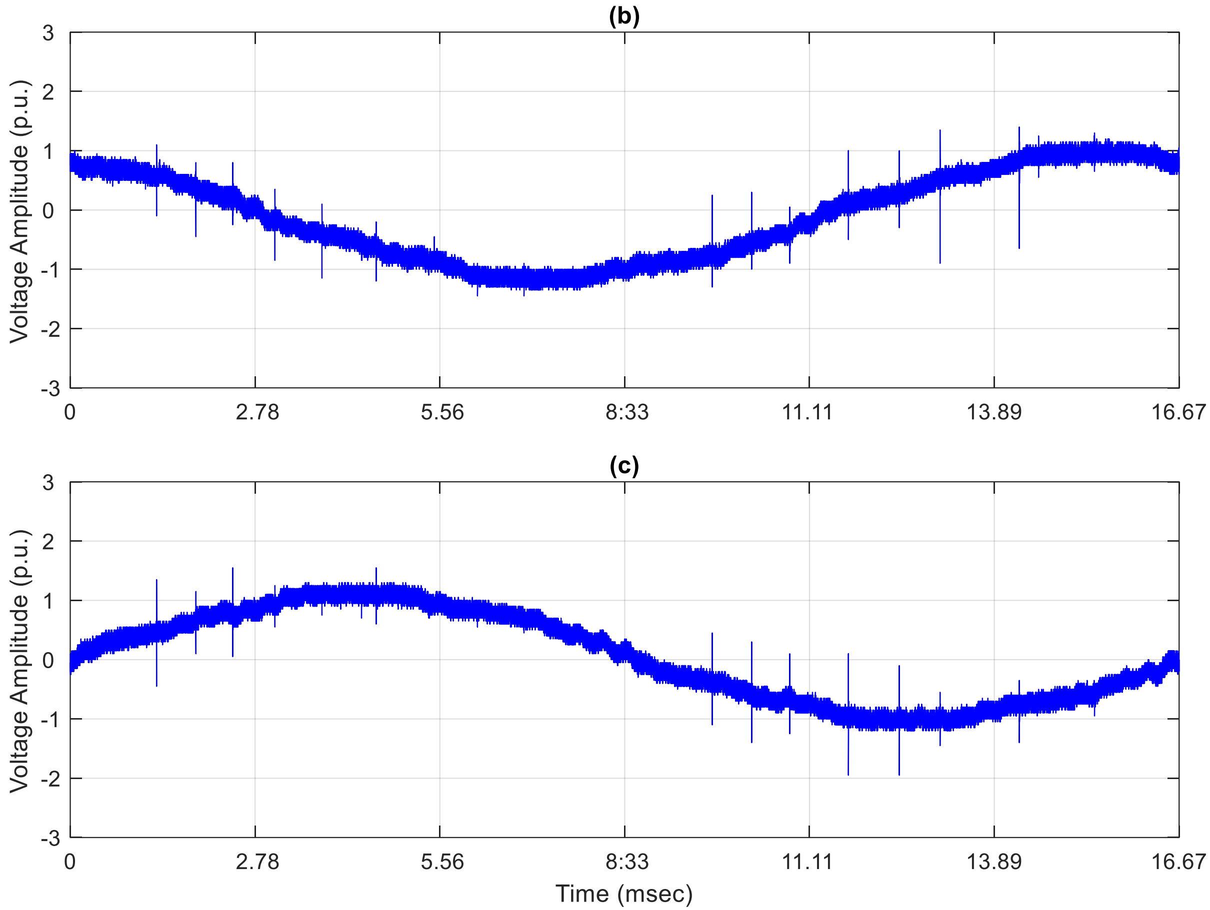
• When it comes to waveform sensors, it can sometimes be very difficult to distinguish abnormal signatures from noise and interference.

• For example, consider the three-phase voltage waveform measurements on the this and next slide that are obtained at an overhead transmission line. Each of the three sub-figures shows the waveform on one phase.



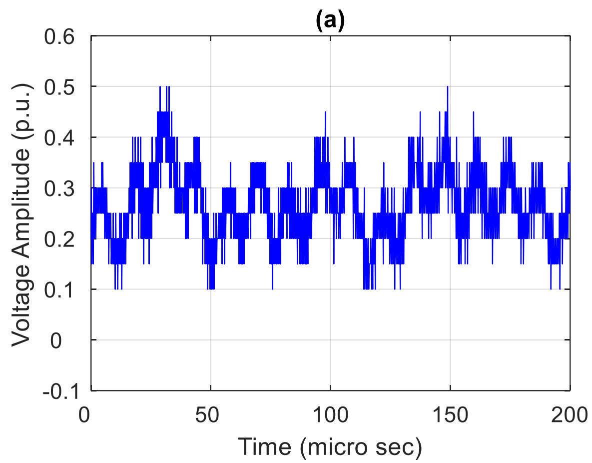
4.7.1. Impact of Noise and Interference

- Voltage waveforms on the other two phases:

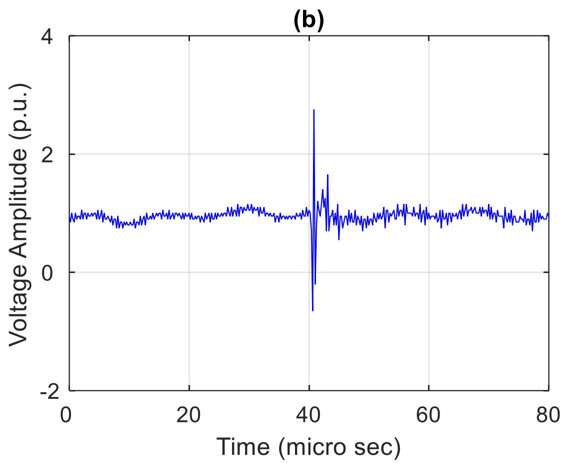


4.7.1. Impact of Noise and Interference

• In Slide 195, we can observe that the measurements appear as noisy in all three phases. For instance, let us zoom in at the two areas that are marked as ① and ② . They are shown in Figures (a) and (b) below:



High-frequency fluctuations in ①



Impulse in ②

4.7 Accuracy in Waveform Measurements

4.7.1. Impact of Noise and Interference

- First, consider the *fluctuations* in Figure (a) in Slide 197.

- Q: Are the fluctuations in ① due to measurement noise in a defected sensor? Or does the voltage at the line conductor actually fluctuate?

  - For the example in this figure, the answer is the latter.

- These fluctuations are due to Discrete Spectral Interference (DSI), which is caused by *radio broadcasting*. An overhead transmission line acts as a long antenna; and therefore, it receives long-wave radio transmissions.

- The biggest permanent source of DSI on the waveform measurements was the 225 kHz carrier wave of a 1 MW transmitter at a radio station that was situated 200 miles away from the measurement site [261].

4.7.1. Impact of Noise and Interference

- Interference from radio broadcasting can vary over time and day. It also depends on depends on some physical factors. [262]. DSIs that are caused by radio broadcasting can often be recognized based on their frequency.

- DSIs can be removed by using adequate *low-pass filters*.

4.7 Accuracy in Waveform Measurements

4.7.1. Impact of Noise and Interference

• Next, consider the *impulse* in in Figure (b) in Slide 197.

• This impulse lasts for only a *few microseconds*. Therefore, capturing this impulse requires a waveform sensor that has a very high time resolution.

• Broadly speaking, this type of impulses could be *benign* if it is due to *Random Pulses Interference* (RPI), which could be caused by transmission line corona, switching operations, etc.

• However, they could also indicate an *incipient fault* if they are due to internal *Partial Discharge* (PD). PDs are known as indicators of degradation of the cable system of the overhead transmission line [263, 264].

4.7 Accuracy in Waveform Measurements

4.7.2. Relative Mean Squared Error

• We may also evaluate the accuracy of a waveform measurement by using the relative *mean squared error* (RMSE), which can be defined over each cycle of the waveform measurement data as follows [248]:

$$\text{RMSE} = \frac{1}{x_{\text{rms}}}\sqrt{\frac{1}{T}\int_0^T \left(\hat{x}(t) - x(t)\right)^2 dt},$$

• where $\hat{x}(t)$ is the reported waveform, $x(t)$ is the true waveform, and x_{rms} is the RMS value of the true waveform. In practice, the integral is turned into a summation over discrete measurements.

• While TVE is defined in *frequency-domain*, RMSE is defined in *time-domain*. RMSE can be used to evaluate the accuracy of waveform measurements during both *steady-state* and *transient* conditions.