KyPSC Case No. 2025-00054
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VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Nick Melillo, Director PGO Asset Management, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

____
Nick Melillo Affiant

Subscribed and sworn to before me by Nick Melillo on this 19th day of August, 2025.

____
NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

Duke Energy Kentucky
Case No. 2025-00054
STAFF's First Request for Information
Date Received: August 12, 2025

STAFF-DR-01-001

REQUEST:

Refer to Case No. 2021-00192.[2]

a. Provide an updated cost estimate for the construction of the substation described by Duke Kentucky as Substation Solution #1, "a smaller substation with a single transformer that would be solely for [Northern Kentucky Water District] NKWD load and which would be owned and operated by them."

b. Provide the estimated annual operations and maintenance cost of a potential substation described by Duke Kentucky as Substation Solution #1.

c. Provide the expected useful life of a potential substation described by Duke Kentucky as Substation Solution #1.

d. Explain whether Substation Solution #1 would be expected to resolve the voltage drop problem for customers other than Northern Kentucky Water District (Northern Kentucky District).

e. Explain whether Substation Solution #1 would be expected to resolve the voltage drop problem for Northern Kentucky District.

f. Explain what hazards or other effects the voltage drop, if any, might create for Northern Kentucky District.

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[2] Case No. 2021-00192, *Electronic Application of Duke Energy Kentucky, Inc. for Approval of a Special Contract and for Waiver of 807 KAR 5:041, Section 6(2)(c)* (filed Aug. 27, 2021), Duke Kentucky's Response to Commission Staff's First Request for Information, Item 2(c), and (filed Jan. 14, 2022), Duke Kentucky's Response to Commission Staff's Second Request for Information, Item 3(a).

g. Explain what hazards or other effects the voltage drop, if any, might create for customers other than Northern Kentucky District.

RESPONSE:

a. The cost estimate for the construction of a dedicated substation that would be solely for Northern Kentucky Water District (NKWD) is $8M. Shown in Table 7 below from STAFF-DR-01-001 Attachment, a Qualitative Evaluation of Mitigation Options for Flicker and Sag conducted by EPRI in March 2025, are the alternative costs for options evaluated. The EPRI report concluded that the STATCOM option is the best solution due to its technical and financial advantages. The STATCOM reduces the voltage drop to 4% on the circuit and has the lowest cost. The Motor Drives option also reduces the voltage drop on the circuit to 4% but at a higher cost. The Dedicated Substation only reduces the voltage drop on the circuit to 5% (so the circuit can't have other customers on it besides NKWD), but it does decrease the voltage drop to 3.3% at the substation so it will not impact other Duke Energy Kentucky customers on the grid. The dedicated feeder option is not feasible since the 12% voltage drop on the circuit would be so large the NKWD pumps would likely not be able to start.

Table 7 Summary of the salient points of various mitigation options

Option	Sag Depth at Substation Busbar	Sag Depth at Water Supply Installation Busbar	Cost (in Millions of Dollars)
STATCOM	N/A	4%	1.5–2
Dedicated Feeder	3%	12%	5
Dedicated Substation	3.3%	5%	8
Motor Drives	N/A	<4%	2.5–4.5

b. The estimated operations and maintenance costs for newer substation options are $10,000-$15,000/year for inspection/testing. Per the EPRI report, the annual maintenance cost for a STATCOM is $30,000/year.

c. Based on the most recently approved depreciation study, the major components of Distribution substation, including transformers, have an approved useful life of 60 years.

d. A dedicated substation should reduce the voltage drop at the substation to 3.3%, which is less than the required 4%. If NKWD remains the substation's sole customer, only their pumps will be affected by any voltage drop.

e. A dedicated substation will not reduce the voltage drop at the NKWD site below the required 4%. Per the EPRI study, the voltage drop at the NKWD site with the dedicated substation option will be 5%, which should not be an issue for NKWD because they are seeing voltage drops higher than this currently. See STAFF-DR-01-001 Attachment for additional detail.

f. Duke Energy Kentucky is not aware of any hazards that the existing voltage drop may have on NKWD equipment/operations.

g. Voltage sags on Duke Energy Kentucky's distribution line can create light flickers, and impact sensitive electronic equipment and industrial processes. Sags can lead to equipment malfunctions, process interruptions, and even damage to equipment. Voltage sags also restrict the operating flexibility of the Duke Energy Kentucky grid. Grid automation and self-healing reconfigures circuits when there is an outage event to restore as many customers as possible. However, temporary outage reconfiguration that would place other customers on the same circuit as NKWD would introduce customers to the voltage drop that do not typically see the voltage drop. These customers would not be accustomed to the voltage drop and may have sensitive equipment that could be impacted by the voltage drop.

PERSON RESPONSIBLE: Nick Melillo

Qualitative Evaluation of Mitigation Options for Flicker and Sag

[Status]

In fulfilment of EPRI contract 20020222 - 10759

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ACKNOWLEDGMENTS

EPRI prepared this report.

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This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner: *Qualitative Evaluation of Mitigation Options for Flicker and Sag:* . EPRI, Palo Alto, CA: 2025. In fulfilment of EPRI contract 20020222 - 10759.

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1 INTRODUCTION

Background and Objectives

The case study presented in this document pertains to one of the largest investor-owned utilities in the United States. In the final quarter of 2024, the utility approached EPRI for help with voltage sag and flicker issues caused by large motor starting events in a water supply installation in its service territory. Other utility customers connected in the vicinity of the water supply installation (also referred to as "customer installation" in this report) would notice lights flickering and other effects associated with fluctuations in source voltage every time water pump motors at the installation were energized.

The customer installation under consideration (that is, the water supply installation) was supplied by a 12.47-kV electric distribution circuit from a utility substation. This circuit also served commercial and residential customers in the area. The water supply installation consisted of six 1,250-hp pumps. To optimize energy costs, these pumps were operated primarily during off-peak hours, resulting in frequent motor start-ups and shutdowns rather than continuous operation. Each pump start-up induced a substantial inrush current, leading to instantaneous voltage sags. For instance, utility engineers had recorded voltage drops exceeding 5%, with a maximum observed drop of 8.8%. Additionally, nearby customers had reported perceptible lamp flicker correlated with pump motor energization.

In order to address the issues caused by motor starting at the installation, the utility had previously engaged an independent consultant. The consultant identified and recommended four potential mitigation strategies:

1. **Implementation of motor drives:** The application of variable frequency drives (VFDs) or a single large drive to regulate motor start-up currents and mitigate voltage disturbances.
2. **Deployment of a VAR compensation solution:** The installation of a STATCOM or similar reactive power compensation system at the water supply installation to enhance voltage stability.
3. **Construction of a dedicated electrical supply system:** Establishing a separate electrical supply system to isolate the water supply installation from other customers, thereby mitigating voltage disturbances on the shared distribution circuit. This approach could be executed in two different ways:
    - Constructing a dedicated feeder from the existing substation feeding the installation.
    - Constructing a dedicated substation for the water supply installation.

In addition to these recommendations, the consultant further noted that the water pump motors at the installation appeared to have soft starters installed, to ease some of the current inrush that accompanies motor energizing. However, it appeared that the soft starters were not optimally tuned. It was also noted by the consultant that additional soft starters would likely not resolve this issue and extending the motor acceleration cycle by adjusting soft-starter parameters may result in thermal damage to the motors.

To meet state regulations and to alleviate the issues being observed by customers in the vicinity of the water supply installation, utility engineers determined that the voltage drop caused by motor energization had to be limited to a maximum value of 4% of nominal voltage. Next, to identify which of the four possible solutions could cost-effectively mitigate the problems being observed, the utility approached EPRI, and a joint project was launched. The main objective of this project was to perform a qualitative assessment of the four strategies identified in the list above and explore any additional potential solutions. To achieve this objective, the EPRI team performed a technical analysis of each methodology with system data from the utility and provided a summary of cost estimates to accompany each strategy. The chief objective of this report is to detail the approach taken to perform this analysis and summarize its main findings.

Approach

To conduct the assessment, EPRI developed a base simulation model of the utility distribution system and the associated water supply installation, in the EMTP[1] simulation platform. Parameterization of this simulation model was performed using system data that was provided by the utility engineering team in the form of a system simulation model in the CYME[2] simulation platform. This CYME simulation model provided by the utility was utilized to perform short-circuit analysis and determine the maximum system strength available to the water supply installation under different operational scenarios, including the proposed ones from the four solution scenarios considered in this project.

Based on the conclusions derived from the short circuit analysis in CYME, EPRI developed a Thevenin equivalent of the utility distribution system at the point of common coupling (PCC) on the utility. The water supply installation was next modeled in the simulation, downstream of the PCC, using transformer, motor, and pump data provided by the water supply installation. To validate the accuracy of the modeled PCC, a fault current matching process was conducted between the EMTP simulation model and short circuit analysis from the CYME model provided by the utility.

In the next phase, EPRI performed simulations to assess the impact of motor start-up at the water supply installation under typical operational conditions on the utility grid. This analysis incorporated the loading conditions of the motors along with their nameplate data to simulate an acceleration transient. Using this simulation of the start-up transient, the resultant voltage sag at the PCC was analyzed. This methodology was employed to evaluate whether a proposed solution could mitigate the voltage sag and flicker issues currently observed.

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[1] https://www.emtp.com/

[2] https://www.eaton.com/us/en-us/digital/brightlayer/brightlayer-utilities-suite/cyme-power-engineering-software-solutions.html

For the evaluation of reactive power (VAR) compensation solutions, a simulation model of a STATCOM was developed. The base model was then utilized to determine the effectiveness of VAR compensation in mitigating the voltage sag and flicker issues identified by the utility. The appropriate sizing and cost estimation of the VAR compensation solutions were also analyzed.

Similarly, for the assessment of the drive solution, an appropriate drive was incorporated into the base simulation model, and the resultant sag performance of the system was analyzed.

Finally, a comparative analysis was conducted to evaluate all mitigation strategies in terms of system performance and implementation cost. The rest of this report is thus organized as follows:

- **Chapter 2** provides a detailed description of the utility distribution system, the water supply installation, and the development of the base simulation model.
- **Chapter 3** presents the simulation results and analysis of various mitigation strategies.
- **Chapter 4** summarizes the conclusions of the study and provides a comparative assessment of the different mitigation techniques.

2 DEVELOPMENT AND VERIFICATION OF SYSTEM SIMULATION MODELS

The previous chapter provided the reader with an overview of the background and objectives of this report. This chapter presents a detailed description of the utility distribution system and the associated water supply installation along with the methodology for developing and validating the simulation models used for the study.

System Description

The initial phase of the project involved gathering the utility system simulation model and nameplate data for the equipment used at the water supply installation. The utility system model was provided in the CYME simulation platform, a widely used software for distribution system analysis. The model consisted of three feeders originating from a 12.47-kV substation. The current system configuration of the utility distribution system, as modeled in simulation, is shown in Figure 1. As shown in this figure, the water supply installation was supplied from feeder 3. Additionally, several other commercial and residential customers were fed from all the feeders originating from the substation. The water supply installation mainly utilized six 1,250-hp pump and motor sets primarily operated during off-peak hours to optimize the energy costs. This operational strategy necessitated frequent motor start-up and shutdown cycles.

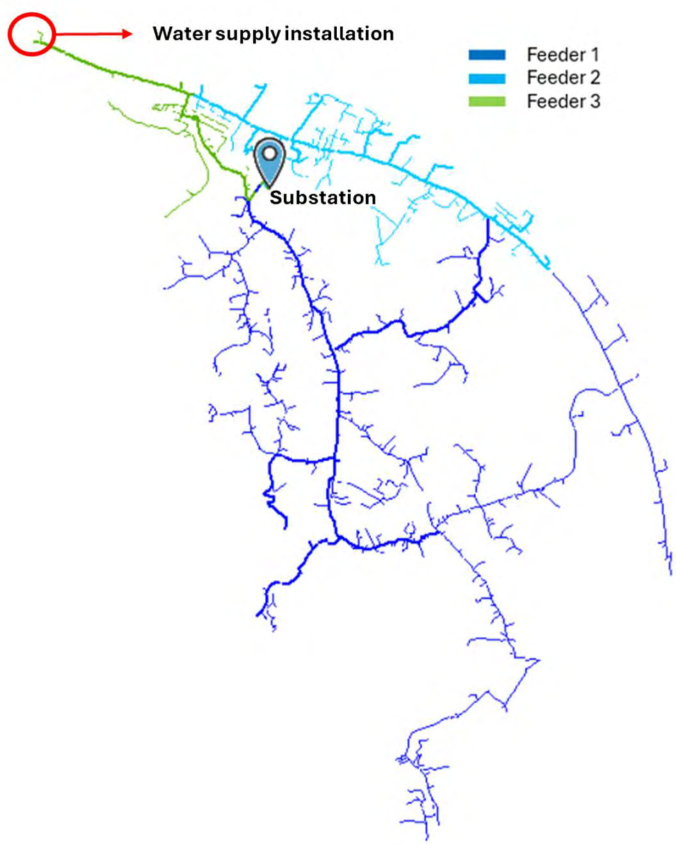

Figure 1 Current layout of the utility distribution system and the relative location of the water supply installation

Large motor starting events generally place stress on power system components. The magnetization of the motor circuit typically leads to six to ten times the normal full-load current being drawn by the electric motor. This excess current drawn from the power grid typically causes large voltage drops through the grid impedance, which is seen as a voltage sag by other end-use loads. Due to the potential for damage to end-use equipment from voltage sags, motor starting events are carefully studied and coordinated by utility engineers and facility designers. In this case, for instance, power quality measurements made by the utility engineering team showed voltage sags with magnitudes greater than 5% on the local distribution system during each motor starting event. Further, the maximum sag depth measured by the utility engineering team on the local distribution system was about 8.8%. These deep sags, in turn, were causing interference issues for other loads connected to the system, with the utility receiving reports of lamp flicker that were correlated to the motor start events at the water supply installation.

Development of the Simulation Model

Using the present system topology of Figure 1 as a starting point, short circuit analyses were next carried out to evaluate the symmetrical short circuit strength of the system at the PCC of the water supply installation. Additionally, the X/R ratio of the distribution system at the installation PCC was also obtained from simulations. These two indices (that is, the short circuit power and the X/R ratio) generally act as indicators of system strength or system "stiffness" at a given PCC. Using these two indices, the system can then be approximated as a Thevenin equivalent voltage source at the PCC, in calculations and in computer simulations. The three-phase short circuit results at the PCC for the system are thus shown in Table 1.

Table 1 Short circuit results for base configuration

Parameter	Value	Units
Three-Phase Short Circuit Current	2415	A
Three-Phase Short Circuit Power	52	MVA
X1/R1	2.83	—
X0/R0	3.01	—

Apart from details of the system strength at the PCC, the other most important consideration in building a simulation model of the water supply installation was the composition of the load inside the installation. To this end, the nameplate data of the motors inside the installation are provided in Table 2. Although the facility contained six motor-pump sets, the specifications of the six motors were nearly identical. Hence, for the sake of brevity, only the details of one motor are shown in this report.

Table 2 Motor nameplate data

Parameter	Value	Units
Full Load Current	154	A
Speed at Full Load	1185	rpm
Power Factor	0.89	—
Efficiency	95	%

In addition to the motor-pump sets, the other major electrical components at the water supply installation were the two transformers that were used to step utility supply voltage down to the motors' utilization voltage. The nameplate data for these transformers is shown in Table 3.

Table 3 Transformer nameplate data

Parameter	Value	Units
Rated Power	5000	kVA
Primary Voltage (L-L)	12.47	kV
Secondary Voltage (L-L)	4.16	kV
Impedance	6.51	%
Winding Configuration	Delta-Grounded Wye	—

Based on the data shown in Table 1 through Table 3, an equivalent simulation model of the water supply installation was developed in the EMTP simulation platform. A schematic of this simulation model is shown in Figure 2. As previously explained, the short circuit capacity of the system at the PCC and the X/R ratio were used to equivalently represent the local distribution system as a Thevenin voltage source behind an equivalent impedance. Additionally, motor parameters were adjusted in simulation to match the field recordings made by the utility engineering team. This enabled accurate simulation of motor behaviors under different conditions. Further, it ensured that a comparison between the various mitigation solutions could be made, with the confidence that the simulation model used for the analysis process reflected field observations as closely as possible.

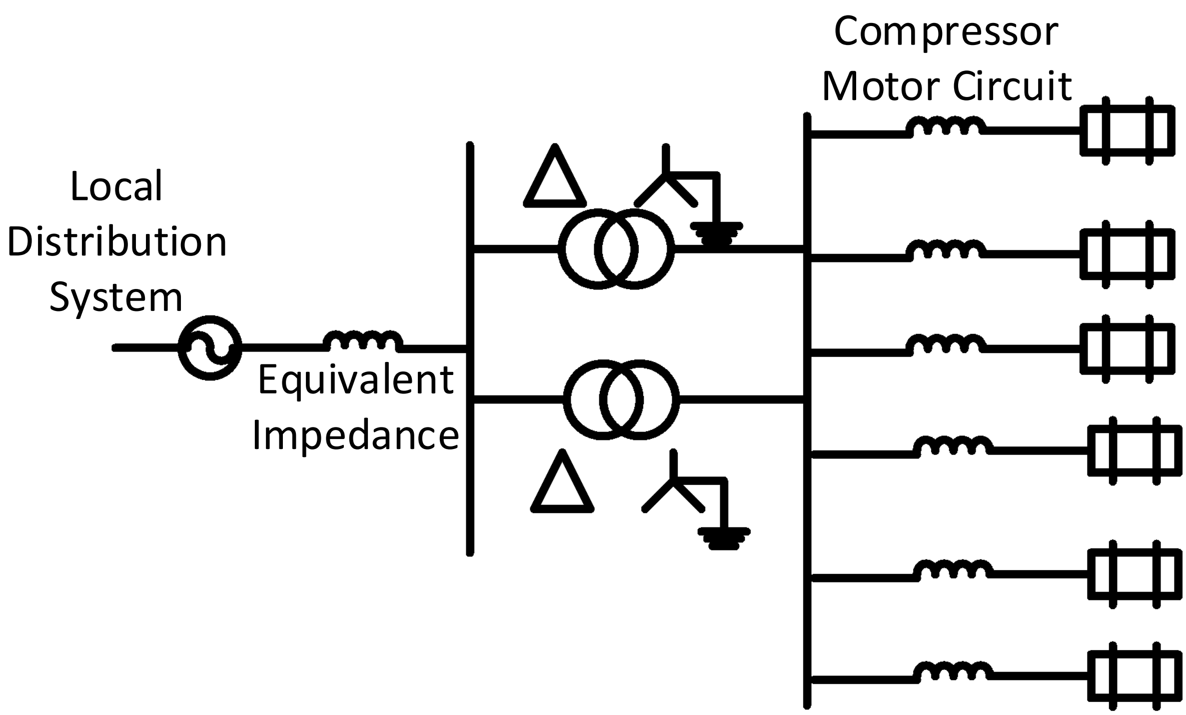

Figure 2 Schematic of the simulation model

Simulation Model Validation

In order to validate the accuracy of the developed simulation model, studies to compare the fault current calculated by the EMTP simulation model against the fault current obtained from the utility-provided CYME model were first performed. In these studies, the symmetrical short circuit current and single line-to-ground fault current at the PCC of the water supply installation were compared. For instance, the symmetrical short circuit current obtained from the EMTP simulation is shown in Figure 3 and Figure 4. Figure 4 in particular shows that the value of this current from EMTP simulation was about 2400 A. On the other hand, it can be seen from Table 1 that the value for the same parameter, obtained from CYME short circuit studies, was about 2415 A. The comparison thus showed a close agreement between the utility-provided data and the developed simulation model in terms of representing the power system as an equivalent source at the installation PCC.

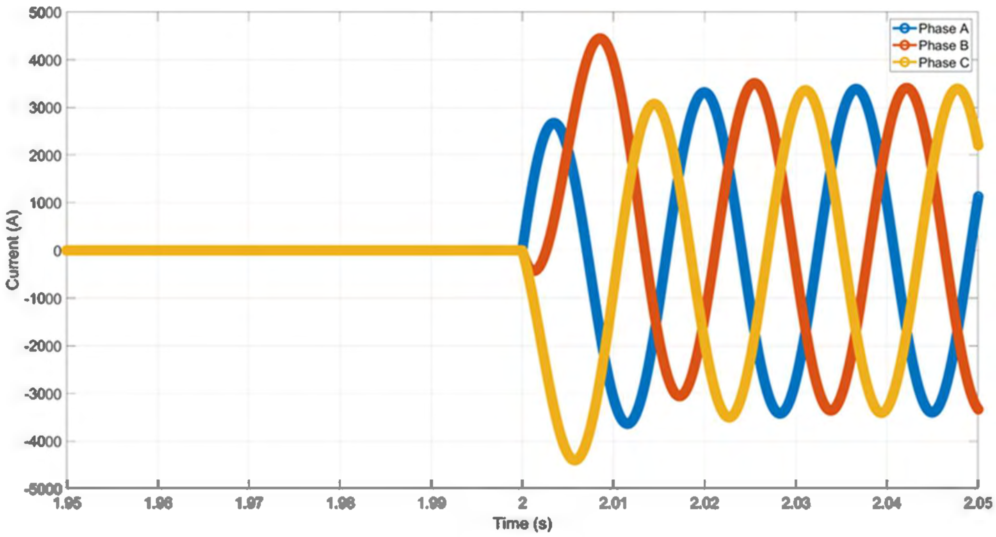

Figure 3 Time domain waveforms of symmetric fault current from the EMTP simulation model

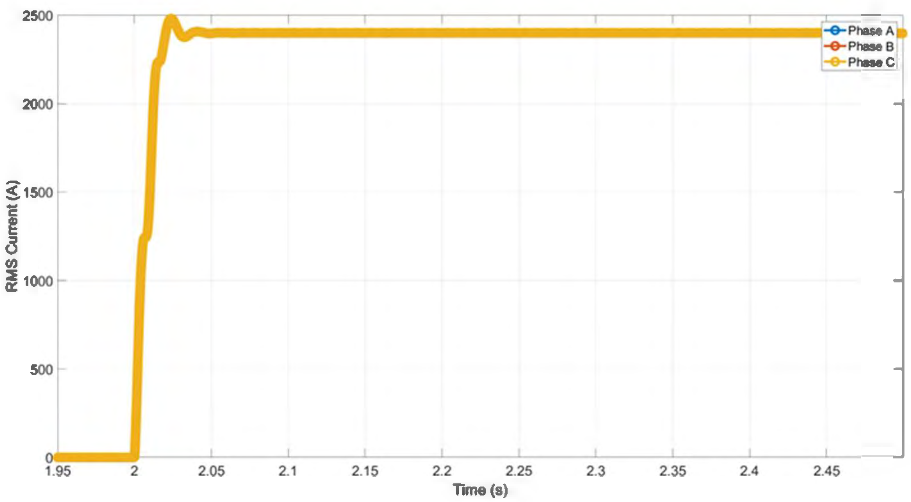

Figure 4 RMS values of symmetric fault current from EMTP simulations

In the next part of the model validation process, the behavior of the motor-pump sets was analyzed for accuracy. For instance, Figure 5 and Figure 6 show the current drawn by a single motor as it was energized from a stand-still condition, while loaded to near-maximum capacity. These plots show that during the energization transient, the motor drew about six to seven times its full load current, peaking at nearly 1000 A. On the other hand, after about 7.5 seconds, after the motor had accelerated to running speed, the motor drew about 158 A of current. This value of full load current again matched very closely with the motor's nameplate current rating of 154 A. Thus, this comparison validated the steady state characteristics of the motor loads.

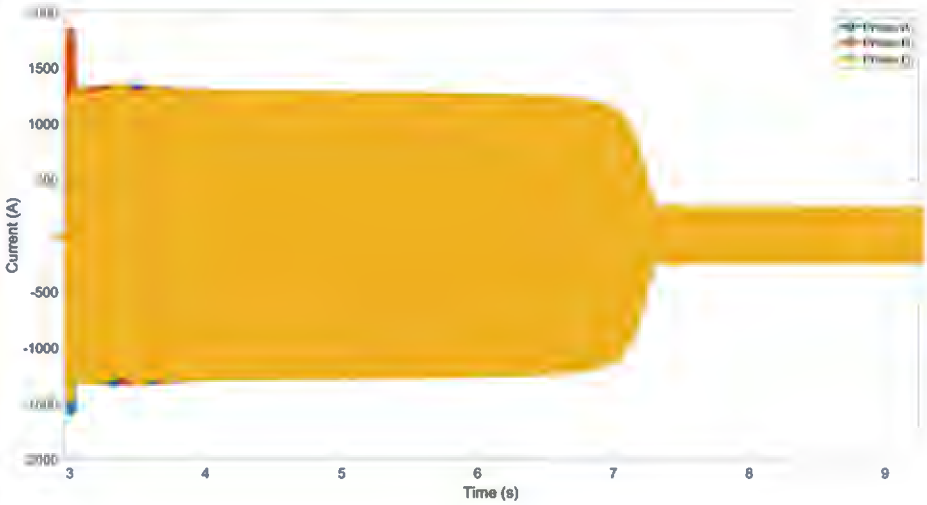

Figure 5 Motor load current from EMTP

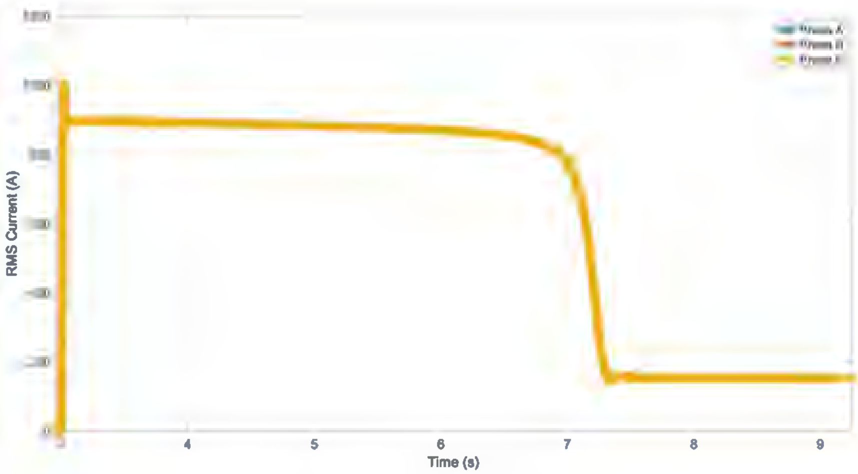

Figure 6 Motor RMS load current from EMTP

In order to validate the transient behavior of the motor during its start-up transient, the voltage dip data recorded by the utility engineering team was utilized next. To compare this field data against the simulation results, a simulation model of two motor-pump sets being energized in succession was first set up. The idea behind energizing two motor-pump sets in succession was to capture the resulting voltage sags on the utility distribution system when:

1. A single motor was energized from a stand-still condition.
2. A single motor was energized from a stand-still condition, while another motor was already energized.

The results from this simulation are shown in Figure 7. This figure shows that the energization of a single motor at the water supply installation caused the PCC voltage to decrease to about 88% of its nominal value, resulting in a 12% decrease in voltage. Furthermore, this change in voltage was not affected by the energization of another motor at the facility—that is, it did not matter if another motor had already been energized on the system previously.

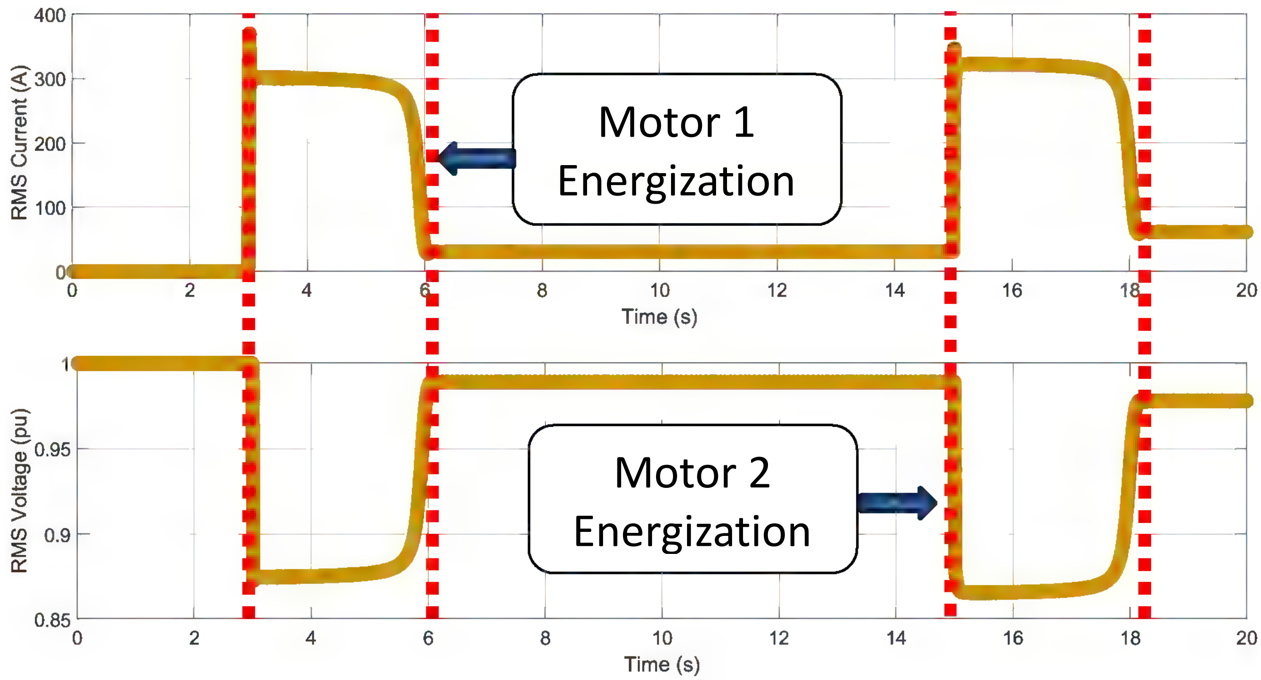

Figure 7 Motor transient characteristics from EMTP. RMS value of motor current is shown in the top figure while the RMS value of PCC voltage is shown in in the bottom figure.

In addition to the energization characteristics shown in Figure 7, the maximum values of active, reactive, and apparent power drawn by the motor during its energization transient are shown in Table 4.

Table 4 Motor initial acceleration characteristics

Parameters	Values	Units
Active Power	2.027	MW
Reactive Power	5.714	MVAR
Apparent Power	6.13	MVA

The simulation results of Figure 7 and the values shown in Table 4 indicated that the initial apparent power drawn by the motor was 6.13 MVA, while the short-circuit power at the PCC was 52 MVA. Consequently, the initial voltage drop could be approximately calculated as:

$$\Delta V = \frac{Apparent\ Power\ drawn\ by\ motor}{Short\ Circuit\ MVA} = \frac{6.13}{52} = 11.78\% \approx 12\%$$

According to the field measurements made by utility engineers, this calculated and simulated value of the initial drop in PCC voltage did not line up with measured values of about 8%. This difference likely arose due to the action of the soft starters that were utilized by the water supply installation, although this could not be verified at the time of writing.

In order to ensure that the simulation values aligned with the observed field recordings made by utility engineers, the value of the subtransient impedance of the motor was adjusted in simulation. This adjustment meant that the initial value of current drawn by the motor was adjusted to 5 per unit (p.u.), instead of 7.5 p.u. This change implied that the initial value of motor current was reduced by a factor of:

$$\Delta I = \frac{Previous\ value\ of\ motor\ transient\ current}{New\ Value\ of\ motor\ transient\ current} = \frac{7.5}{5} = 1.5$$

This change in the motor transient current implies that the voltage sag will get modified to a value of:

$$\Delta V = \frac{Previous\ value\ of\ voltage\ sag}{1.5} = \frac{11.78}{1.5} = 7.85\% \approx 8\%$$

To verify if these changes would actually help align the field measurements with simulation results, the simulation with two motors being energized in succession was repeated. The results of this simulation are shown in Figure 8. This figure shows that after making the appropriate modification to the motor subtransient reactance, the energization of a single motor at the water supply installation would cause the PCC voltage to sag to a value of 92%. This reduction implied that the change in voltage under these conditions would be about 8%, matching the field observations made by the utility engineering team. These modifications thus ensured that the simulation model matched real life observations made by the utility engineering team and demonstrated sufficient accuracy for use in the study. The developed simulation model thus was considered as the “baseline case,” against which the effectiveness of various mitigation techniques could be evaluated. Descriptions of these mitigation techniques and their technical analysis are thus presented in the next chapter.

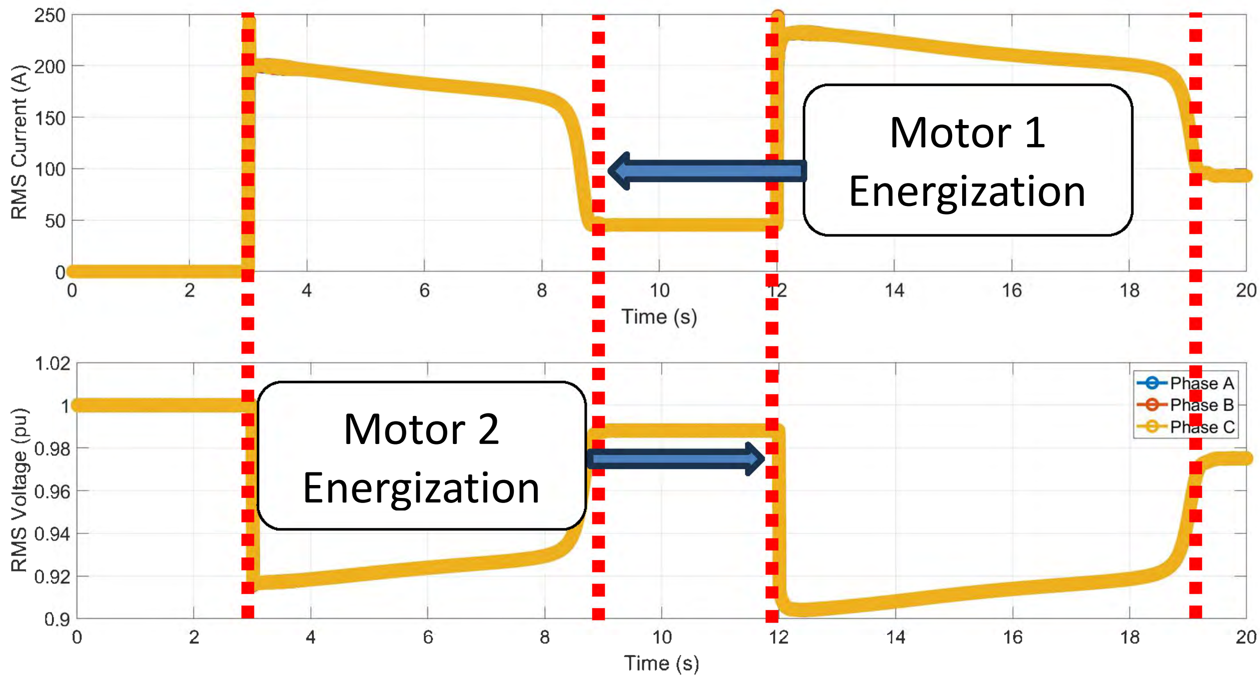

Figure 8 Motor transient characteristics from EMTP after modification

3 SIMULATION RESULTS AND ANALYSIS OF VARIOUS MITIGATION TECHNIQUES

The previous chapter described the process of developing an equivalent simulation model of the current topology of the utility distribution system and the water supply installation. As discussed in Chapter 1, in the next step, four different mitigation techniques were qualitatively and technically evaluated using this base simulation model, to compare the merits of each technique. The mitigation techniques explored in this report are:

- Building a dedicated feeder circuit for the water supply installation
- Building a dedicated substation for the water supply installation
- Utilization of a STATCOM to provide VAR compensation to the water supply installation
- Utilization of a drive for the motor-pump sets to mitigate the energization transient caused by motor starting

The sections of the chapter that follow are dedicated to discussing various aspects of the qualitative evaluation of each solution. In each of these evaluations, along with the technical merit of the solution, practical details that may be relevant to the utility during the implementation of the solution are further discussed. Finally, the chapter closes with a summary comparison of the various solutions and the conclusions that the utility may draw from this comparison.

Assessment of Dedicated Feed and Dedicated Substation

As shown in Figure 1, the water supply installation was supplied from a 12.47-kV substation with three feeders. Additionally, the feeder serving the water supply station also supplied other commercial and residential loads. Initial analysis conducted based on the simulation model discussed in Chapter 2 indicated that one of the primary causes for the deep voltage sags could be the relatively low value of short circuit strength at the water supply installation PCC. This low value of short circuit strength was likely the result of the location of the installation, being at the end of the supply feeder, where system impedance would be highest and consequently short circuit strength would be the lowest.

As Chapter 1 discussed, the utility had calculated and determined an internal target of limiting the change of voltage (ΔV) on the distribution system resulting from motor starting to 4%, to ensure that disruption did not occur for other customers connected to their distribution system. To achieve this internal target, two possible approaches were then identified by the utility:

1. **Isolate the impact of voltage sags.** The first solution identified by the utility essentially aimed at isolating the effects of the voltage sag resulting from motor starting at the water supply installation. This isolation can be achieved by building a dedicated circuit for the installation. Any sag resulting from motor starting at the water supply installation could then be isolated from the other customers being fed from the utility distribution system.

2. **Improve short circuit strength.** By improving the short circuit strength at the PCC, the utility aimed to reduce the change in voltage, resulting from motor starting at the water supply installation, to a value less than 4%. Such an increase could thus ensure that interference with other utility customers could be avoided. In practice, an improvement in short circuit strength can be achieved by connecting the customers as close to the transmission system as possible—that is, by building a dedicated substation for the customer.

The reliability and stability of the power supply to the water supply installation could be significantly improved through the adoption of these two approaches. However, each approach entailed significant capital investment on the part of the utility. Hence, the utility engineering team wanted to ensure that the efficacy and practical aspects of each solution were thoroughly analyzed. This qualitative analysis of these two approaches is presented next.

Construction of a Dedicated Feeder for the Water Supply Installation

Detailed plans for the construction of a dedicated feeder for the water supply installation were provided by the utility engineering team. In these plans, from the existing substation, overhead and underground cables were planned to be laid and connected to the water supply station. The planned total length of the feeder from the substation to the connection point was approximately 5.6 miles. Next, the utility engineering team developed a CYME simulation model for the planned dedicated feeder based on these engineering plans and provided them to EPRI. The layout of this dedicated feeder in the CYME simulation model and the relative location of the water supply installation are shown in Figure 9. Based on this simulation model, EPRI then performed short circuit analysis studies at the planned PCC of the water supply installation. The short circuit results at the PCC with the dedicated feeder simulation model are shown in Table 5.

Table 5 Short circuit parameters at the installation PCC from the dedicated feeder simulation model

Parameter	Value	Units
Three-Phase Short Circuit Current	1559	A
Three-Phase Short Circuit Power	39	MVA
X1/R1	4.03	—
X0/R0	3.1	—

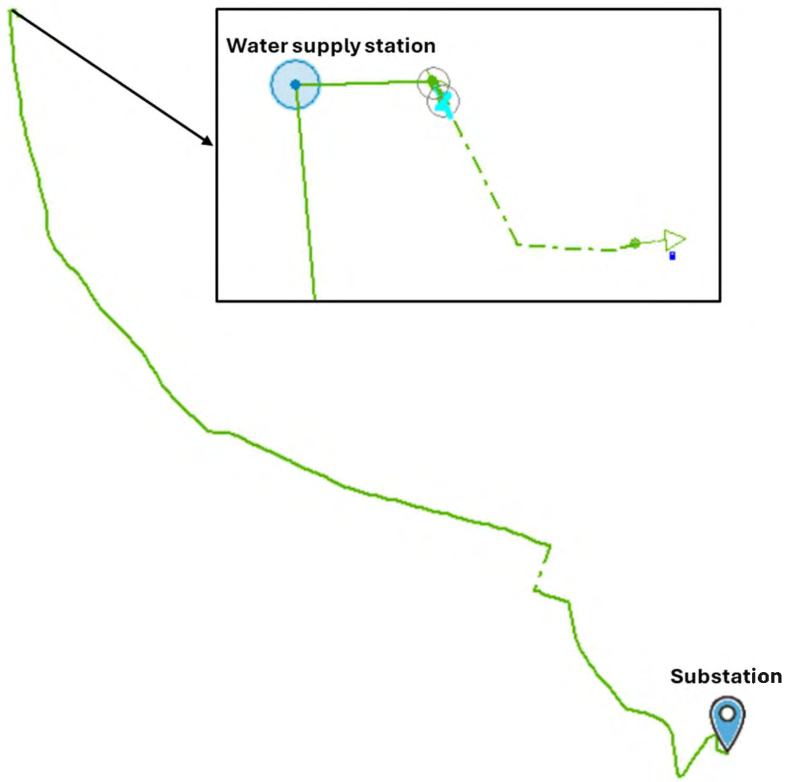

Figure 9 Schematic of the dedicated feeder showing the relative location of the water supply installation from the CYME model

An initial examination of Table 5, and a comparison with the results of the base case simulation (Table 1), shows that, in general, the proposed dedicated feeder solution would lead to a lower short circuit strength at the PCC of the water supply installation. More precisely, compared to the short circuit strength (52 MVA) at the water supply installation in its present system topology, the proposed dedicated feeder would have a 25% lower short circuit strength at the PCC of the installation.

To qualitatively evaluate the effect of the dedicated feeder on the water supply installation, a new simulation model was next created in the EMTP simulation platform. This simulation model followed the same modeling approach as that described previously—that is, in this simulation model, the substation was represented as a Thevenin equivalent voltage source behind an equivalent impedance. Furthermore, the impedance of the dedicated feeder was obtained from the CYME simulation model and represented in the EMTP simulation model accordingly. Finally, the water supply installation was represented in the EMTP simulation model, exactly as described in Chapter 2. An equivalent schematic of the simulation model developed in EMTP is shown in Figure 10.

Utilizing this simulation model of Figure 10, the efficacy of the dedicated feeder solution was next analyzed. To perform this analysis, an operational scenario of energizing two motors in succession was simulated in EMTP. The results of this simulation are shown in Figure 11.

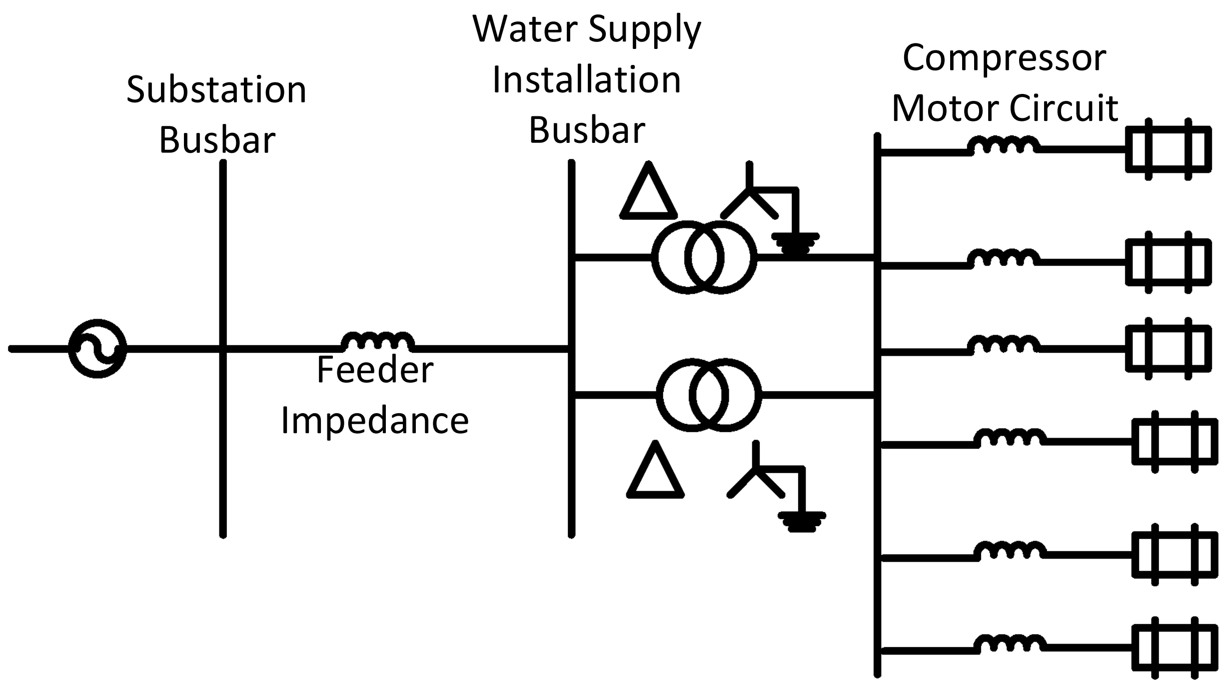

Figure 10 Equivalent schematic of the EMTP simulation model developed for evaluating the dedicated feeder solution.

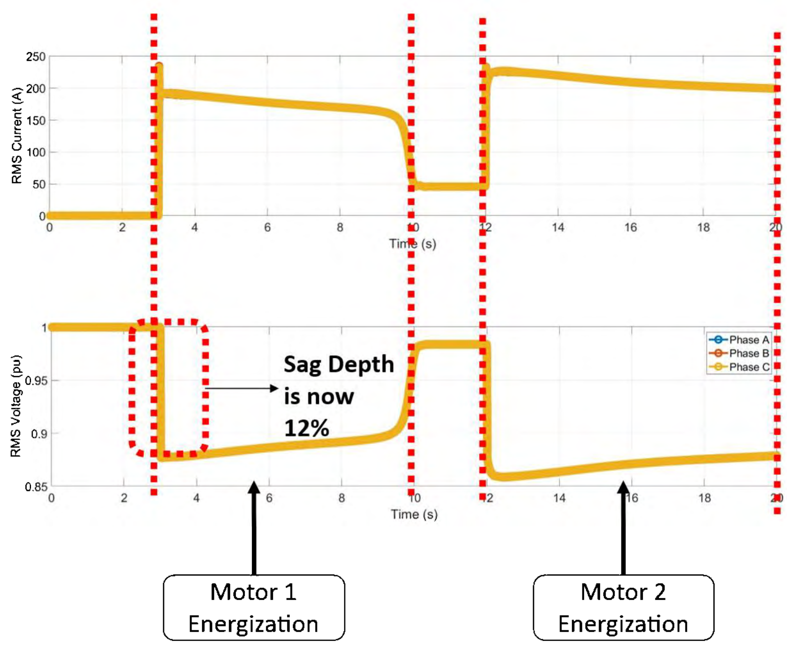

Figure 11 RMS voltage at the PCC (bottom) and current drawn by the motors (top) from EMTP simulation

Based on the observation of reduced system strength at the PCC with this solution (as apparent from Table 5), unsurprisingly, Figure 11 shows that the voltage sags caused by motor starting at the installation become worse in this operational scenario. For instance, Figure 11 shows that the sag depth at the installation PCC increased to 12% in this operational scenario. Compared to the base case value of 8%, this operational scenario thus shows a 50% increase in sag depth. This observation largely aligns with expectations, since a reduced system strength implies a softer source and hence deeper system sags.

Contrary to the preceding discussion, the observation of deeper system sags at the installation PCC does not offer a full picture of the efficacy of the dedicated feed. This is because the key aspect of this solution is the voltage sag that is observed on the distribution system (and not necessarily the PCC). As Figure 10 shows, this sag is different from the voltage sag at the PCC. Since the dedicated circuit would have the water supply installation as the sole load connected on it, the voltage sag from motor starting that would be seen on the distribution system would be the one that occurs on the substation busbar. This is because other feeders connected to the same substation would share the substation busbar with the dedicated feeder for the water supply installation. Figure 12 shows the voltage profile at this substation busbar, from the simulation of two successive motor starts as depicted in Figure 11.

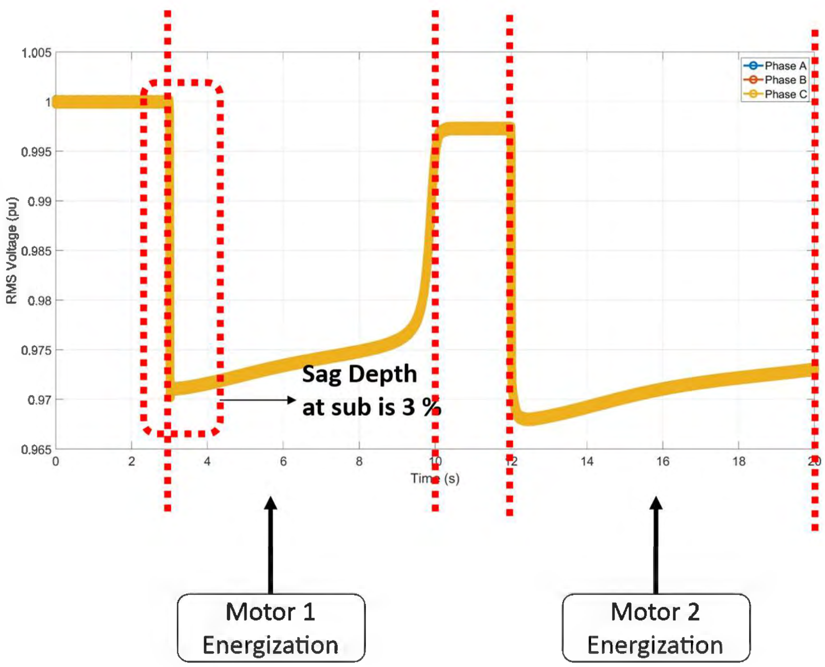

Figure 12 RMS voltage at the substation busbar

Figure 12 shows that, unlike the PCC of the water supply installation, the voltage at the substation busbar would only have a sag depth of about 3%. This observation implies that, in principle, the dedicated feed would enable the utility to limit the impact of motor starting as seen by other distribution system load to 3%. This would enable the utility to meet its internal target of limiting voltage change on the distribution system to less than 4%. However, at the same time, the sag depth of 12% that would be seen at the PCC voltage in this operational scenario could potentially prove to be problematic for the water supply installation. For instance, voltage sags of such depth can cause protection and control devices to trip offline.

Such trappings can lead to process disruption for the load and lead to monetary losses. Hence, even while restricting the *system impact* of motor starting to 3%, this solution could lead to unacceptable voltage sags for the water supply facility, leading to protection and control equipment tripping offline and causing process disruptions. For this reason, this solution was unsuitable from a water supply installation perspective.

As a final discussion point in the qualitative analysis of the dedicated feeder solution, it is worth discussing the differing values of the voltage sags, as observed at the substation busbar and at the PCC of the water supply installation in this study. For this purpose, it is worth looking at the fault current values along the length of the dedicated feeder, as shown in Figure 13. This figure shows the values of symmetrical short circuit current and line-to-line fault current along the length of the feeder. In the case of each of the fault current values, a general trend of reduction of available fault current from the system, with increasing distance from the substation, can be observed. This can be explained on the basis of the increase in system impedance along the length of the feeder. This decreasing fault current indicates that the system is typically “stiffer” or “stronger” near the substation and “softer” near the end of the feeder. In the instance of the dedicated feeder solution under study, the available fault current at the substation was 6500 A, while the available fault current at the installation was 1559 A. This meant that the system had about four times as much fault current at the substation as at the water supply installation. In the case of the water supply installation, the change in voltage or the sag depth that results from motor starting was about 12%. From this number, an approximation of the sag depth at the substation can be obtained, using the fault current values shown in Figure 13:

$$\Delta V_{substation} = \frac{\Delta V_{installation}}{\frac{Fault\ current\ at\ substation}{Fault\ current\ at\ installation}} = \frac{12\%}{\frac{6500}{1559}} \approx 3\%$$

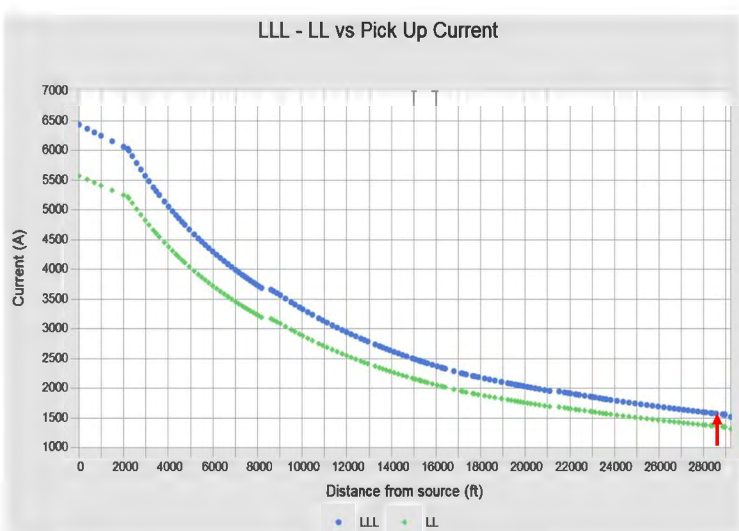

Figure 13 Distance vs. short circuit strength with dedicated circuit (red arrow shows location of the water supply installation)

The preceding discussion effectively summarizes the thought process behind the dedicated feeder solution. Even though the sag depth at the PCC was 12%, the higher available fault current at the substation busbar meant that the effects of motor starting would be mitigated at the substation busbar. Thus, the variation in fault current along the feeder can effectively be exploited to isolate the effects of the voltage sag from the rest of the distribution system. Figure 14 provides a summary of the overall system performance with the dedicated feeder solution. The voltage sag at the PCC will be approximately 12% in this case, resulting in a minimum voltage of 0.88 p.u. This, in turn, will cause a 3% voltage sag on other feeders originating from the substation, leading to a minimum voltage of 0.97 p.u. at the substation.

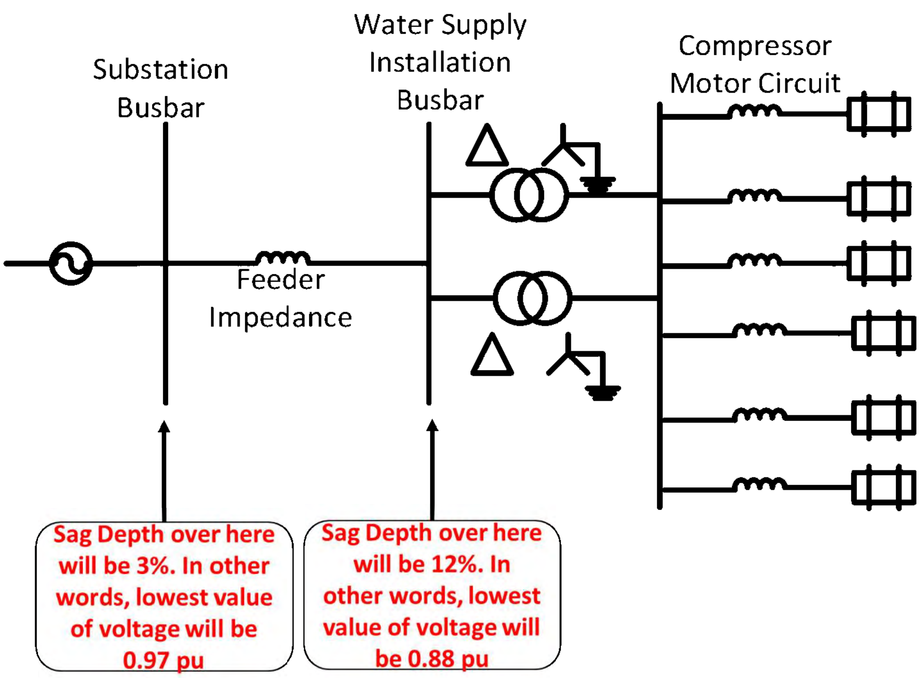

Figure 14 Sag performance summary with the dedicated feed solution

Construction of a Dedicated Substation for the Water Supply Installation

The next solution approach considered by the utility engineering team was the construction of a dedicated substation for the water supply installation. As previously explained, the chief objective of this solution was to improve the available short circuit strength at the water supply installation PCC by placing the installation closer to the utility transmission system or by directly feeding it from the transmission system. As was the case with the previous solution, detailed engineering plans and a CYME simulation model for this solution was provided to EPRI by the utility engineering team. The feeder length in this proposed solution method was 1.25 miles, originating from the dedicated substation and terminating at the water supply installation. Figure 15 shows a schematic of this solution from the CYME simulation model, while short circuit results for the installation PCC from this simulation model are presented in Table 6.

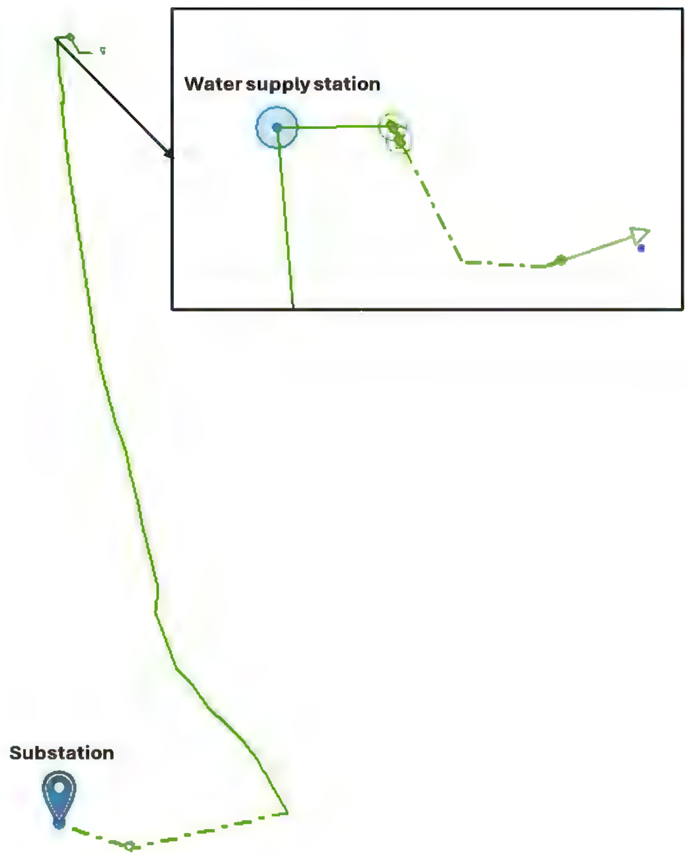

Figure 15 Schematic showing the dedicated substation and the water supply installation from the CYME model

Table 6 Short circuit parameters at the installation PCC from the dedicated substation simulation model

Parameter	Value	Units
Three-Phase Short Circuit Current	3964	A
Three-Phase Short Circuit Power	85.6	MVA
X1/R1	8.09	—
X0/R0	3.38	—

Table 6 shows that with the dedicated substation solution, the short circuit strength at the PCC, would be 85.6 MVA. Compared to the base case system strength of 52 MVA, the installation PCC in this case was stronger by a factor of about 1.6. Following the reasoning previously presented, it would be inferred from these numbers that the expected sag depth in this case would decrease by a factor of 1.6. Since the sag depth in the "base case" was about 8%, this would imply that the sag depth in this case would be:

$$\Delta V_{new} = \frac{\Delta V_{base\ case}}{\frac{Fault\ MVA\ with\ substation}{Fault\ MVA\ in\ base\ case}} = \frac{8\%}{\frac{85.6}{52}} \approx 5\%$$

In order to verify that this new value of the sag depth was accurate, a simulation was once again set up in EMTP, using the exact same process as described in the previous section and with the same layout as shown in Figure 10, albeit with updated parameters corresponding to the dedicated substation solution. The results for the sag depth at the PCC obtained from this simulation are shown in Figure 16. These results confirm the results obtained mathematically from the equation shown previously—that is, that the sag depth for the water supply installation would be 5% with a dedicated substation.

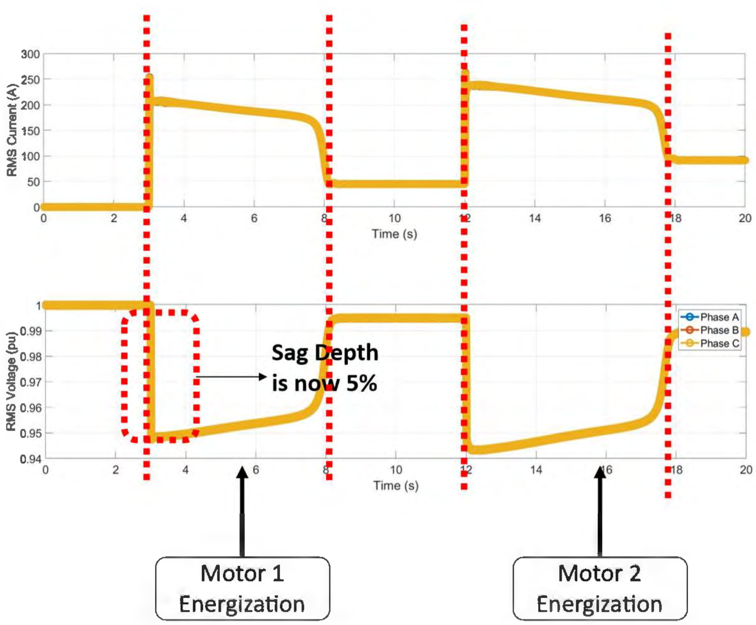

Figure 16 Sag performance at PCC with dedicated substation

As with the dedicated feeder solution, the reader may have guessed that the voltage sag value at the substation busbar would be different from the value of the voltage sag at the installation PCC. In other words, in this case also, it is reasonable to expect that the system impact of motor starting at the installation would be different from the impact at the PCC. Figure 17 shows this system impact of motor starting, from the same simulation as the one from Figure 16. In this case, Figure 17 shows that while the voltage sag at the installation PCC was 5%, the sag depth from the same event would be about 3.3% at the substation. In other words, the distribution system would experience a 3.3% sag depth from motor starting at the water supply installation.

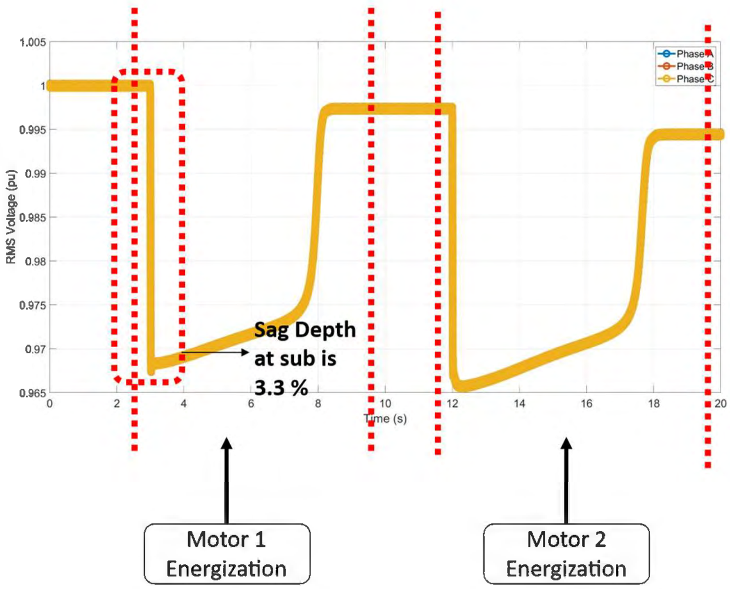

Figure 17 Sag performance at substation busbar with dedicated substation

Figure 18 shows the overall system performance with the dedicated substation. In this case, as with the dedicated feeder, the substation is intended to feed only the water supply station, so no other customer would be affected by the motor starting events. However, the sag depth at PCC would be around 5% causing the voltage to drop to 0.95 p.u.

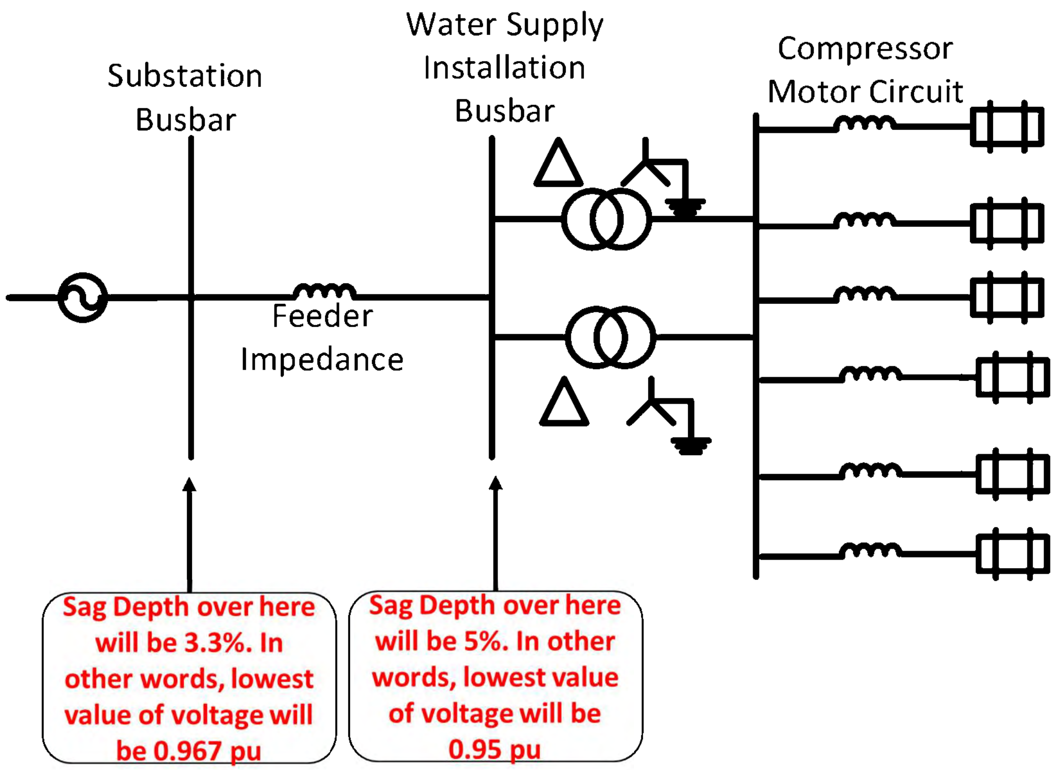

Figure 18 System performance evaluation with dedicated substation

Figure 18 shows that the dedicated substation solution would limit the system impact of motor starting to a sag of depth 3.3%. This value would meet the utility target value of 4%. Furthermore, while the PCC would experience a sag depth of 5%, this would not be deep enough to cause significant disruption to the water supply installation. In conclusion, therefore, it can be said that the dedicated substation solution would effectively alleviate all the negative effects associated with motor starting at the water supply installation.

Assessment of VAR Compensation Solution

Fundamentals of STATCOM

A static synchronous compensator (STATCOM) is a shunt-connected, power electronic device used in electrical distribution systems to enhance power quality by providing dynamic reactive power compensation. Figure 19 shows that the STATCOM includes a voltage source converter (VSC) that may utilize either insulated-gate bipolar transistors (IGBTs) or gate turn-off thyristors (GTOs), which are self-commutated devices and capable of very fast reaction times. Hence, STATCOMs generally react in one to two cycles. Because VSCs utilize DC capacitors, the STATCOM generally has very little active power capacity, unless paired with a source of energy storage. In a STATCOM, power electronics are used to achieve the reactive current control. For example, if the voltage of the VSC control bus is higher than the compensated bus, the STATCOM injects reactive current into the system. On the other hand, if the voltage at the compensated bus is higher than the bus voltage at the VSC, the VSC absorbs reactive power. It goes without saying that closed loop control is required for this operational capability of the STATCOM. Depending on the requirements of the application, STATCOMs may use two-level, three-level, or modular multilevel converters.

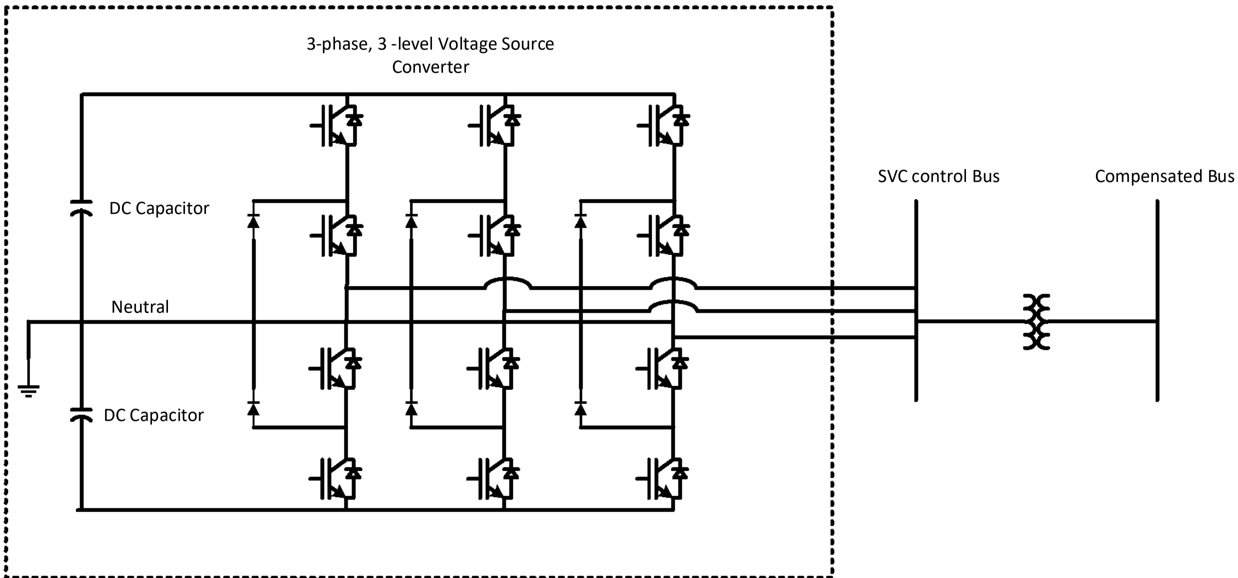

Figure 19 Simplified single-line diagram of a three-phase, three-level neutral point clamped converter STATCOM

Assessment of STATCOM Mitigation Technique

To demonstrate the effectiveness of a STATCOM in mitigating the voltage sags caused by motor starting at the water supply installation, the EMTP simulation model of the base case from Chapter 2 was once again utilized. Since STATCOMs compensate for the lack of available reactive power at any point in the grid, typically STATCOMs are placed in shunt with the load being compensated. For instance, in EMTP simulation, a STATCOM was connected in shunt with the water supply installation at its 12.47-kV busbar. A schematic showing this arrangement in simulation is shown in Figure 20. In this instance, it is assumed that a mobile STATCOM unit can be purchased and deployed to alleviate the voltage sag issues.

For the STATCOM system implemented in simulation, four parallel STATCOM modules, each rated at 2.5 MVA, were utilized, resulting in a total reactive power capacity of 10 MVA. Each STATCOM module was equipped with a 2.5 MVA, 6% impedance, delta-wye grounded transformer and operated in voltage regulation mode. In this mode, the STATCOM was designed to stabilize the voltage at the water supply installation PCC to 1.0 p.u. by injecting reactive power during motor acceleration, thereby limiting the voltage drop at the PCC.

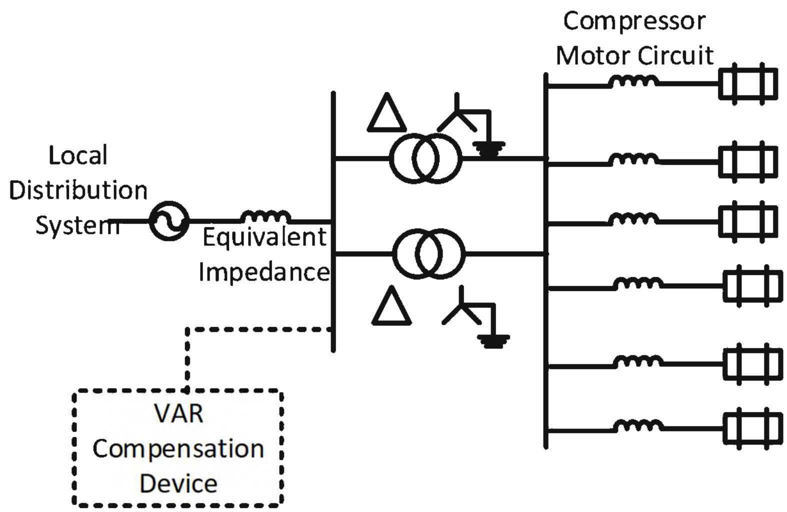

Figure 20 Simulation schematic showing the application of a STATCOM for mitigating motor starts at the water supply installation

The action of the STATCOM in regulating the PCC voltage can be understood on the basis of Figure 21 and Figure 22. These two figures show that as the motor starts to accelerate in simulation at time *t* = 0, the STATCOM begins to inject reactive power into the PCC busbar. This reactive power had a peak value of about 3.5 MVAR. Due to this injection of reactive power, the initial minimum value of PCC voltage was restricted to 0.955 p.u., resulting in a 4.5% sag depth. After this initial drop in voltage, due to the continuous injection of reactive power by the STATCOM, PCC voltage recovered in about 5 seconds to a value of 1 p.u. After the voltage at the PCC busbar reached the setpoint of 1 p.u., the STATCOM then kept meeting the reactive power demand of the load—that is, the motors in the installation—to maintain the voltage at this setpoint. The oscillations being observed in Figure 21 and Figure 22 were a result of the proportional-integral-derivative (PID) controllers not having been optimally tuned. With proper tuning, the depth of the voltage sag at the PCC busbar could be further minimized, enhancing system stability and power quality.

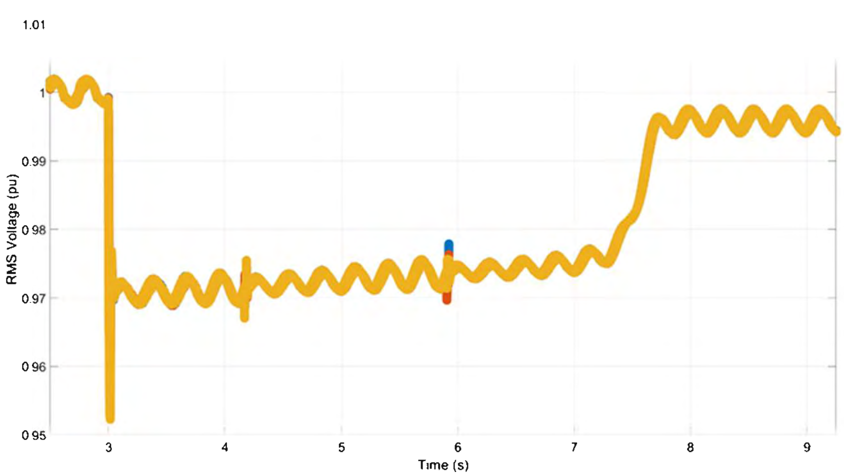

Figure 21 Plot of PCC RMS voltage from simulation

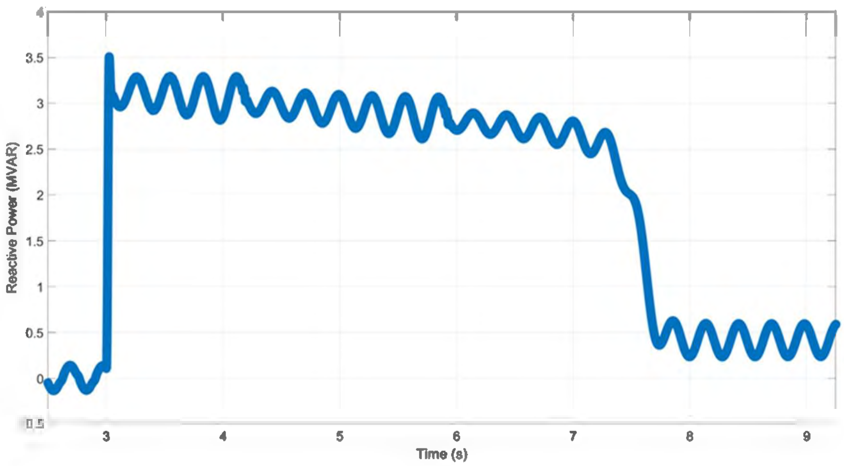

Figure 22 Plot of reactive power injected by the STATCOM into the PCC busbar from simulation

As a final point in the discussion of the STATCOM solution, it is worth noting that even though the sag depth of 4.5% obtained with this mitigation solution did not meet the utility target of 4% sag depth, the simulations used for this study were not optimized for evaluating a STATCOM solution and were only meant to give a close approximation of the mitigation achievable. Hence, even though the sag depth obtained from simulation was slightly higher than the utility's target, the utility engineering team and EPRI agreed that a properly sized and tuned STATCOM would very likely alleviate the voltage sag problem under study. In addition, the potential stacked benefits of STATCOMs—such as load power factor improvement, harmonic mitigation, and flicker mitigation—made this an attractive solution strategy.

Assessment of a Motor Drive Solution

A motor drive operates by gradually ramping up the input voltage frequency while simultaneously increasing the motor voltage during acceleration, resulting in a smooth and nearly disturbance-free acceleration cycle. As shown in Figure 23, a motor drive has three main parts: a rectifier, a DC bus/link capacitor, and an inverter. The incoming AC voltage is converted to DC voltage by the rectifier. This rectified voltage is then cleaned by the DC bus/link capacitor to reduce its ripple content. Finally, the inverter converts the rectified DC voltage into a variable frequency and variable magnitude AC voltage, which is then supplied to the motor to control its speed and torque. As the input voltage to the motor is very closely regulated in this process, the inrush current drawn by the motor can be very effectively controlled by a motor drive.

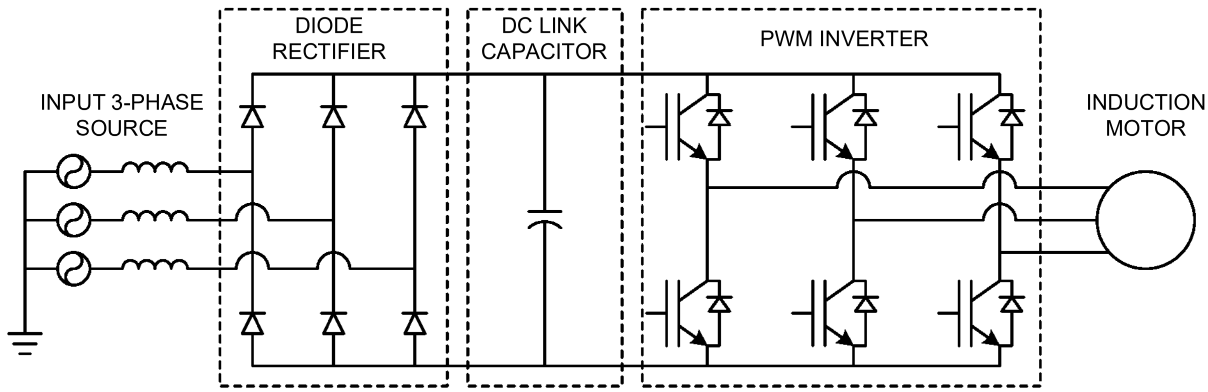

Figure 23 Schematic of an induction motor drive

To demonstrate the efficacy of a motor drive in controlling the inrush current of a motor, the base case EMTP simulation from Chapter 2 was once again utilized. In this simulation, a modification was made so that each simulated motor was supplied through a drive. An average value model of a 1250-hp drive, utilizing field-oriented control (FOC), was used for this purpose. Furthermore, in the simulation model of the drive, the FOC algorithm was implemented using pulse-width modulation (PWM) control. The control objective of the drive was next set to speed control, and a simple scenario was set up. This scenario can be described as follows:

1. At time $t = 0$, the drive was commanded to accelerate the motor to its full load speed of 1185 rpm.
2. During the acceleration transient, the motor drive was commanded to increase the speed gradually, with a ramp profile.
3. After accelerating to full speed, the drive was commanded to hold speed constant until time $t = 3.5$ seconds.
4. At time $t = 3.5$ seconds, the drive was commanded to decelerate the motor to zero speed.
5. After the motor reached zero speed, the drive was commanded to accelerate the motor to full speed reverse operation and then hold this reverse speed till the end of the simulation.

The output from the simulation of the motor drive solution is shown in Figure 24. This figure shows that by implementing drive solution, sag depth can be reduced to nearly 0. In all acceleration cycles, the FOC algorithm was able to effectively clamp motor inrush current so that the PCC voltage did not experience any sags during the acceleration cycles. The slight oscillations that can again be seen in the simulation results, are due to the suboptimal tuning of the PID control loops. Hence, the simulation results show that the motor drive solution would be likely to effectively solve the problem of voltage sags being caused by motor energization. Practical aspects of the implementation of this solution, along with all other solutions, are thus discussed next.

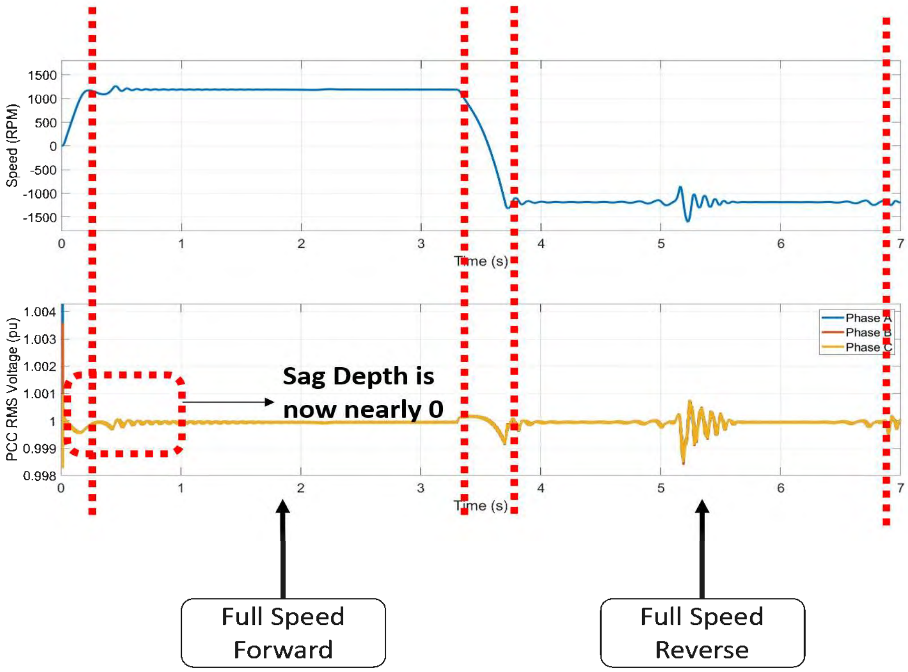

Figure 24 Motor speed (top) and PCC RMS voltage (bottom) from the simulation of a drive solution

Practical Aspects of Mitigation Solutions

The foregoing sections of this chapter showed that, to a large extent, all solutions could potentially alleviate the problem of voltage sags being observed by the utility due to large motor starting at the water supply installation. However, each solution presents unique challenges to the utility and the water supply installation that warrant further discussion. These challenges include considerations of cost, ease of implementation, and potential impacts to the system and/or water supply installation. These practical aspects are thus discussed next.

Dedicated Feeder

As discussed in the previous sections of this chapter, the utilization of a dedicated feeder for the water supply installation would effectively isolate the voltage sag effects of motor starting at the water supply installation. This solution would limit the voltage sag on the distribution system to a sag depth of only 3%, ensuring that minimal interference with other system load would result. The primary drawback of this solution, however, lies in two considerations:

1. The magnitude of the voltage sag at the PCC would be 12%, which would result in protection and control equipment tripping offline at the water supply installation, leading to process interruption and monetary loss. Such interruptions would be unacceptable from the perspective of the customer and the utility.
2. The utility estimated that the cost of building a new dedicated circuit for the water supply installation would be about $5 million, which would potentially be higher than some of the other mitigation solutions under consideration.

Ultimately, due to the high cost of implementing the solution and the significant risk of causing disruptions to the water supply installation despite these high costs, the utility engineering team considered this solution to be less preferable.

Dedicated Substation

Similar to the dedicated feeder solution, the idea of building a dedicated substation also showed significant promise in alleviating the voltage sag issues caused by large motor starting at the water supply installation. This solution could potentially overcome one of the big drawbacks of building a dedicated feeder, by restricting the voltage sag at the installation PCC to 5% (as opposed to 12% for the dedicated feeder solution). Furthermore, as was demonstrated through simulation analysis, this solution could restrict system impact to a sag depth of 3.3%, ensuring minimal interference for other system load. However, despite these advantages, this solution presents the following two challenges:

1. The cost of building a dedicated substation is substantial, with the utility estimating a total cost of about $8 million for this task.
2. The lead time for building a new substation would be several years, which would likely be unsuitable for the problem at hand.

Owing to these two considerations, this solution was considered impractical and difficult to implement for the problem at hand.

Motor Drive

In the previous section, it was shown that motor drives would likely be very effective in eliminating voltage sags due to motor starting. The proposed solution approach was based on the installation of a dedicated drive for each individual motor, with six motors and hence six drives in total. The estimated equipment cost for a 1250-hp motor drive ranged between $200,000 and $250,000, with the total installed cost typically being two to three times the equipment cost. Further, each drive system would occupy a physical footprint of approximately 10 feet in width, 8 feet in depth, and 10 feet in height. While a single drive solution for all six motors is theoretically feasible, it would likely require a custom-built design rather than an off-the-shelf product. The cost and footprint of such a customized solution could not be accurately estimated without direct input from the original equipment manufacturer (OEM). These considerations highlight the following limitations of this solution:

1. The cost of implementing this solution would likely be in the range of $2.5 to $4.5 million. Further, in the case of utilizing a single drive rather than six, the cost of making a custom-built drive may also be in the same range.
2. The physical footprint of the drives may be problematic, especially if the available real estate at the water supply installation is limited.

Besides these factors, the water supply installation had estimated that systems for heat dissipation from the drives and physical enclosures would also have to be built, which would add to the solution cost. Further, the cables and the motors currently being used at the water supply installation may not be inverter rated. This would require expensive upgrading as well. As a result, the actual cost of implementing the drives may be significantly higher.

STATCOM

Apart from the solutions discussed thus far, the STATCOM promised to be the easiest to implement. Unlike the solutions previously described, a STATCOM implementation would likely not require building custom parts, since the technology behind them is mature. STATCOMs tend to be modular and, due to their stacked benefits, offer versatility in operation. For the voltage sag application under discussion, the utility anticipated a cost of $1.5 to $2 million for the STATCOM along with a $30,000 per year maintenance cost. Another possibility that the utility could consider in this regard would be the adoption of a mobile STATCOM, which would be installed on a tractor trailer that would provide mobility to the solution. This would ensure that the utility could potentially use the STATCOM in other applications, in case of operational or topological changes that would no longer require a STATCOM to be used.

Summary Discussion

The preceding discussion highlighted the limitations and practical aspects of each solution under consideration. Table 7 provides a summary of the salient points of this discussion. Due to prohibitively high costs and long lead times, the dedicated feeder and dedicated substation solutions would prove to be infeasible. Furthermore, due to limitations of available space and the motors and cables not being inverter-rated, the drive solution would be less cost-effective to implement as well. In light of these considerations, the STATCOM solution would likely be the best candidate for solving the voltage regulation problems being caused by motor starting at the water supply installation. Hence, the STATCOM was considered to be the solution of choice based on the techno-economic analysis conducted for this project.

Table 7 Summary of the salient points of various mitigation options

Option	Sag Depth at Substation Busbar	Sag Depth at Water Supply Installation Busbar	Cost (in Millions of Dollars)
STATCOM	N/A	4%	1.5–2
Dedicated Feeder	3%	12%	5
Dedicated Substation	3.3%	5%	8
Motor Drives	N/A	<4%	2.5–4.5

4 CONCLUSION

Based on the work presented in this report, the following broad conclusions can be drawn:

- This project demonstrates that building dedicated feeders for customers does not necessarily alleviate the problem. The location of the customer and the feeder impedance to it matter and can become a limiting factor. On the other hand, building a dedicated feeder and a dedicated substation are time consuming and expensive affairs, and this hinders their use in such cases.
- Although the motor drive proved to be a great solution to alleviate the problem at hand, practical considerations of cost and limitations of existing equipment and infrastructure would likely limit the implementation of this solution.
- The STATCOM, with its standard and modularized design, was considered the solution of choice due to considerations of cost and ease of installation.
- Power quality mitigation is not a “one size fits all” type of exercise. A solution that works in one case may not necessarily work in another. Load limitations and considerations of cost and space have to be taken into account in each case, along with system conditions. Hence, the experience and input of utility power quality engineers is extremely important in such studies.

Duke Energy Kentucky
Case No. 2025-00054
STAFF's First Request for Information
Date Received: August 12, 2025

STAFF-DR-01-002

REQUEST:

Identify any customer complaints related to voltage drop on the affected circuit and provide any documentation of these complaints.

RESPONSE:

Duke Energy Kentucky has not received any customer complaints due to the NKWD-related voltage drops in the last four years. This is likely and partially because customers impacted by the voltage drop have become accustomed to the voltage drops. Also, the KYPSC approved special contract reduced the number of daily pump starts and shifted those starts to the midnight-4am timeframe which reduced the observable voltage drops of most customers.

Customer complaints related to NKWD are listed below:

It is also important to keep in mind that if a new customer with sensitive electronic equipment locates on the NKWD circuit they may have significant issues that could lead to complaints with Duke Energy Kentucky.

- March 21, 2013 – 38 Southview, Fort Thomas, KY (WO# 3971835)
- April 16, 2013 – 263 Sergeant, Fort Thomas, KY (WO# 4034722)
- April 17, 2013 – 252 Sergeant, Fort Thomas, KY (WO# 4039060)
- April 22, 2013- 81 South Crescent Avenue, Fort Thomas, KY (WO# 4050917)

- September 10, 2014 – 77 South Crescent Avenue, Fort Thomas, KY (WO# 6224986)
- January 30, 2015 – 9 North Crescent Avenue, Fort Thomas, KY (WO# 7140729)
- April 7, 2015 – 225 Mulberry Court, Fort Thomas, KY (WO# 7533124)
- May 5, 2016 – 617 Mary Ingles Hwy, Fort Thomas, KY (WO# 10374401)
- March 7, 2017 – 225 Mulberry Court, Fort Thomas, KY (WO# 20875342)
- July 30, 2018 – 100 Carmel Manor, Fort Thomas, KY (WO# 29278065)
- August 2, 2021 – 107 Pinnacle Dr, Fort Thomas, KY (WO# 41729502)

PERSON RESPONSIBLE: Nick Melillo

Duke Energy Kentucky
Case No. 2025-00054
STAFF's First Request for Information
Date Received: August 12, 2025

STAFF-DR-01-003

REQUEST:

Refer to the special contract.[3] Identify all instances in which Northern Kentucky District has started a pump outside of permitted hours under the emergency provision of the special contract.

RESPONSE:

Please see STAFF-DR-01-003 Attachment which includes the dates that Duke Energy Kentucky has email notifications from NKWD about pumps starting outside of the permitted hours. However, due to email retention policies the Company does not have all the email notifications dating to the start of the special contract (March 4, 2022).

PERSON RESPONSIBLE: Nick Melillo

[3] Case No. 2021-00192, Application (filed June 6, 2021), Attachment 2 at 2.

Northern Kentucky Water District

Account Number	Address
	200 Mary Ingles Fort Thomas, KY 41075

Date	Reason	# of pump starts
9/22/2023	communication failure with our monitoring equipment	1
10/26/2023	DE Power Outage with ETR at 3:45p.m caused pump start outside of time window 12-4a.m	1
12/11/2023	Preventative Maintenance	1
1-12/24-1/15/24	pump troubleshooting	multiple
2/28/2024	equipment failure	1
4/30/2024	power failure	1
5/16/2024	install new pump motor	2
6/7/2024	Maintenance and Resivoir Cleaning - Pumps were off and needed to be started were started inside of window	3
7/31/2024	Pump malfunction causes an additional pump start in its place at 2:05p.m	1
8/7/2024	Maintenance at pumps at ORPS 1- 3 additional pump starts during daytime hours	3
8/27/2024	Three additional starts between 8am-10a.m- annual maintenance	3
8/30/2024	Accidental pump start	1
9/24/2024	DE Power Outage- Two additional starts 7:47 AM	2
12/5/2024	Mechanical Issues - 1 pump start befroe midnight	1
3/4/25-4/25/25	Went back to normal operation while the special contract was not in effect	multiple/day
5/12/2025	annual electrical preventative maintenance tests	2
5/13/2025	annual electrical preventative maintenance tests	2
6/24/2025	SCADA Programming Issue - high production due to heat 2 pump starts	2

Duke Energy Kentucky
Case No. 2025-00054
STAFF's First Request for Information
Date Received: August 12, 2025

STAFF-DR-01-004

REQUEST:

Refer to Duke Kentucky's deviation from 807 KAR 5:041, Section 6(2)(a) and (c). Explain what Duke Kentucky asserts Duke Kentucky and Northern Kentucky District's individual duties are if the deviation from 807 KAR 5:041, Section 6(2)(a) and (c) terminates.

RESPONSE:

Objection, to the extent this request calls for a legal opinion. Without waiving said objection, KRS 278.030(2) requires every utility to furnish adequate, efficient and reasonable service. To enforce that requirement, the Commission has adopted, among other things, regulations regarding the voltage that must be delivered by regulated electric utilities. Specifically, 807 KAR 5:041, Section 6(1) requires an electric utility to adopt a standard nominal voltage for its distribution system or for distinct portions thereof. Section 6(2) of that regulation then states, in relevant part, that:

> (2) Voltage at the customer's service entrance or connection shall be maintained as follows:
>
> (a) For service rendered primarily for lighting purposes, variation in voltage between 5 p.m. and 11 p.m. shall not be more than five (5) percent plus or minus the nominal voltage adopted, and total variation of voltage from minimum to maximum shall not exceed six (6) percent of the nominal voltage.
>
> (b) For service rendered primarily for power purposes, voltage variation shall not at any time exceed ten (10) percent above or ten (10) percent below standard nominal voltage.
>
> (c) Where utility distribution facilities supplying customers are reasonably adequate and of sufficient capacity to carry actual loads normally imposed, the utility may require that starting and operating characteristics of equipment on customer premises shall not cause an

> instantaneous voltage drop of more than four (4) percent of standard voltage nor cause objectionable flicker in other customer's lights.

Section 6(6) of 807 KAR 5:041 allows for "[g]reater variation of voltage than specified under [Section 6(2)] if in a limited or extended area in which customers are widely scattered or business done does not justify close voltage administrative regulation." However, Section 6(6) still requires "the best voltage administrative regulation shall be provided that is practicable under the circumstances." Section 22 of the regulation states that "[i]n special cases for good cause shown the commission may permit deviations from these rules."

Duke Energy Kentucky maintains that its facilities are adequate and of sufficient capacity to provide service and to carry actual loads normally imposed. The voltage sags are caused by NKWD starting its pumps, and once the initial start-up occurs, and the pumps are running and the power requirements level out, the Company's facilities are adequate and do not experience the sags. Pursuant to 807 KAR 5:041, Section 6(2)(c), Duke Energy Kentucky may require NKWD's equipment to operate in such a way as to not cause the voltage sag of more than 4 percent. Duke Energy Kentucky has previously requested NKWD to take action, but to date, NKWD has not cured the issue. Thus, the need for the waiver and special contract. Duke Energy Kentucky believes it is NKWD's responsibility to resolve the issue caused by their equipment. Duke Energy Kentucky's only other alternative would be to threaten disconnection.

PERSON RESPONSIBLE: As to objection, Legal
As to response, Nick Melillo