



Dean LaForest
Manager of Strategic System Planning
Vermont Electric Power Company, Inc.
366 Pinnacle Ridge Road
Rutland, VT 05701
dlaforest@velco.com
Direct: 802-770-6323

July, 11th 2008

Stephen J. Rourke, Vice President
ISO New England System Planning
One Sullivan Road
Holyoke MA, 01040-2841

RE: TCA Application Northwest Reliability Project Revision 1 – Request for Information #01
VELCO-03-155-01-R1, VELCO-03-155-02-R1, VELCO-03-155-03-R1, VELCO-03-155-04-R1

Dear Mr. Rourke,

Please find attached the additional information requested for the revised Transmission Cost Allocation (“TCA”) Northwest Reliability Project application as requested on May 16th 2008. You will find below the questions/answers relating to project update as described in this revision.

Also, let me take this opportunity to explain the change in Queen City costs as discussed at the June 2008 Reliability Committee. When we were preparing for the May 29th, 2008 stakeholder forum, we double-checked all of our costs incurred to date and found that we had failed to split out those non-PTF costs for the Queen City substation construction efforts. We captured those non-PTF costs and reported the change in the materials provided at the May 29th, 2008 stakeholder meeting and changed the motion voted at the June 2008 RC meeting to reflect the lower PTF costs. The costs for the Queen City substation, based on our incurred costs as presented at the stakeholder meeting, are \$5.8M PTF and \$2.5M non-PTF for Queen City versus the preliminary estimate of \$8.3M PTF and \$0M non-PTF.

Please do not hesitate to contact us should you have further questions on the material provided here or on other TCA matters with regard to the NRP. You may contact me at the my office via phone at 802-770-6323 or e-mail via dlaforest@velco.com. Please also copy Jose Sebastiao (802-770-6495 & jsebastiao@velco.com) with any further queries to help insure we meet your needs.

Sincerely,

Dean LaForest

cc: Carissa Sedlacek, ISO-NE, José Sebastiao, VELCO, Ernie Hiatt, VELCO, Tom Dunn, VELCO



A. Regarding general questions Related to all four (4) TCA applications.

Q. A-1 Were the original estimates done in 2003 dollars or in future year dollars with escalation? If no escalation was used, please explain why. If escalation costs were used, please explain how they were calculated. (i.e., escalation percentage)

A. A-1 The original TCA application was estimated by the A/E firm using 2003 dollars. The cost estimate at the time was a planning grade estimate and did not specifically include escalation costs. At the time, recent project experience were smaller scale and magnitude, with low escalation rates (in the 2% to 3% range) and therefore had a limited impact on project cost. Therefore, in the original TCA application, these costs were omitted in planning grade estimates.

Using the current methodology VELCO has presented to various committees and groups, the project escalation from the original TCA application should have been estimated at \$46.9 million (excluding the Sandbar substation upgrade executed shortly after the TCA was filed). Escalation rates experienced during the course of the NRP were in the 6% to 10% range in average depending on the cost category.



Q. A-2 Explain why AFUDC was never included in the original estimate

A. A-2 The original estimate included a limited amount of AFUDC based on past experience when project funding at the time and their estimates were assembled using a much shorter timeframe for engineering and design, procurement, and project permitting. Lower interest rates combined with lower projects scale reflected in much lower AFUDC costs. AFUDC was typically accounted as part of the direct cost.

This economic aspect is now captured on all cost estimates VELCO develops and appear as a separate cost category. AFUDC in the case on the Northwest Reliability Project are projected to account for a project increase of \$16.1 million.



Q. A-3 Were the Indiana Bat Mitigation Plan, Rare/Irreplaceable Habitat Mitigation Plan, Osprey Report, or Update of EMF Health Effect Issues Report used as references on the project? If so, what was the cost associated with the creation/procurement of each of these reports, and how were these costs allocated to each of the Project TCA applications?

A. A-3. These reports have been used on the Northwest Reliability Project in support of the permitting process. The following cost were associated with these environmental studies and allocated to each revised TCA application as follows:

- Indiana Bat Mitigation Plan \$37,000
- Rare/Irreplaceable Habitat Mitigation Plan \$24,400
- Osprey Report \$4,200
- Update of EMF Health Effect Issues Report \$136,800

STUDY	T01	T02	T03	T04	TOTAL
Indiana Bat Mitigation Plan	\$ 2,400	\$ 11,500	\$ 10,900	\$ 12,900	\$37,000
Rare/Irreplaceable Habitat Mitigation Plan	\$ 900	\$ 4,400	\$ 6,300	\$ 12,800	\$24,400
Osprey Report	\$ 100	\$ 400	\$ 300	\$ 3,400	\$4,200
Update of EMF Health Effect Issues Report	\$ 9,600	\$ 46,900	\$ 42,400	\$ 37,900	\$136,800

(Values Rounded to the nearest hundred)

The cost associated with these environmental studies occurred during the permitting and were treated as permitting cost. These costs were then allocated to the various project components based on their overall cost share of the NRP or specific when applicable.



Q. A-4 Confirm that there were no revisions to the original Design, Aesthetic Mitigation or Landscape Mitigation Plan (if required) for the following substations: Essex, Williston, Hartford, Blissville and New Haven. If revisions were made, please explain who requested the Design, Aesthetic Mitigation or Landscape Mitigation Plan revision. What costs were associated with these revisions.

A. A-4. The following design changes were made:

- Hartford changes requested by VELCO:

- *Existing Circuit switcher on high side of transformer was replaced with 115kv Breaker.*

Reason: Existing Circuit switcher were under rated given the available short circuit current. Breaker substitution is a more cost effective solution to accomplish this function and performs better.

Incremental Cost: None.

- Williston changes requested by VELCO:

- *Separate Control Building added and expanded from 20' x 30' to 32' x 48'.*

Reason: Required by NESC Handbook Fifth Edition (*Rule 125 Working Space About Electrical Equipment*).

Incremental Cost: \$225K (includes all associated direct & indirect costs – 2005). This does not include cost savings associated with increased productivity gains by building a new control house vs. expanding the existing one.

- New Haven changes requested by Public Service Board Order:

- *Substation Site Relocation 800 ft southwest of the existing substation.*

Reason: The Public Service Board required the relocation of the substation to an alternate site limiting the aesthetic impact imposed by the substation expansion.

Incremental Cost: As per VELCO filed testimony, the new proposed site created and estimated incremental cost between \$1.8M and \$2.3M (2004 estimate includes PTF and Non PTF, excluding escalation). The incremental cost includes 46kV rebuild in the new site as well as additional excavating and grading site work.



Incremental Cost (Cont’): As to the substation sitework:

Sitework Incremental Cost	Final Cost	Original Site (As Filed)	Relocated Site (PSB Order)	Incremental Cost
Site Clearing and Rough Grading (SqFt)	\$4,256,379	272,488 SqFt	531,000 SqFt	\$2,072,175
Crushed Stone & Backfill (CuYd)	\$1,556,811	35,780 CuYd	60,000 CuYd	\$628,433

Total: \$2,700,608

(Total Cost, including PTF & Non PTF, substation final allocation was 94% PTF, transformer excluded)

Per the Public Service Board order in docket no. 6860, VELCO was ordered to relocate the substation approximately 800 feet to the southwest of the existing location. The relocated substation site required considerable excavation of material that required disposal. This material was subsequently used on site to construct a berm. Use of this material on site eliminated the need for off-site disposal which saved approximately \$600,000.

In addition, construction at a greenfield site greatly enhanced construction productivity and reduced safety concerns associated with working in an energized substation. VELCO estimates a 30% productivity gain when working in a green field for Labor. This represents an estimated saving of \$2.9M (\$9.6M Labor cost). This results to the new site being a better cost alternative:

The total net saving with relocating the substation is estimated at **\$800,000**.



Q. A-5 What was the total number of condemnations that were realized by this Project and what was the economic impact of these?

A. A-5. For the NRP 370 line project, (part of VELCO-03-TCA-155-T03) **one (1)** condemnation is in process. The settlement led to compensation **95%** lower than the asked price. The additional condemnation proceeding legal costs was estimated at **\$360,000**. This proceeding, the first in 30 years, was explored to its full extent. As a consequence this cost is much higher than recent experience in other similar cases (averaging \$80,000). For the NRP 115 kV line project (part of VELCO-03-TCA-155-T04) there are currently **four (4)** active condemnations. Since none of these processes have reached final conclusion at this time, it has not yet been possible to evaluate their economic impact beyond the information provided above. Please see our separate letter provided for our estimates of the potential economic impact. Due to the nature of the information provided, we request that the ISO keep this information confidential.



Q. A-6 As presented in the PowerPoint presentation to the Reliability Committee Meeting on April 15, 2008, describe the difference between "equipment" and "materials."

A. A-6. As presented in the material provided during the Reliability Committee presentation:

- Material Cost: refers to the materials purchased for the construction of the projects (e.g. poles, insulators, wire, transformers, breakers ...)
- Equipment: refers to the rental of equipment used to install these materials (e.g. cranes, boom truck, helicopter...)



B. The following questions are with respect to TCA application VELCO-03-155-01-R1

Q. B-1 At the Blissville Substation, please explain the reliability-based justification for increasing the MVA Rating of the PST being installed by 75%.

A. B-1. The reliability based justification for the MVA rating purchased and installed for the Blissville PST is:

- This PST design has a proven track record at another VELCO installation (Sand Bar).
- The unit installed at Blissville can replace the units at Sand Bar and Granite for an equipment failure scenario.
- The unit installed at Blissville is not the limiting element thermally in the circuit from Blissville to Whitehall, NY and can accommodate changes to the limiting facilities in either New York and/or New England and still not become the limiting element on the Whitehall – Blissville – West Rutland 115 kV circuit.
- The Whitehall – Blissville 115 kV line is a key NY-NE transmission tie-line that has been thermally limiting transfers in the past. Installing a PST at Blissville with thermal margin that should encompass its useful life (approximately 30 years) is VELCO’s practice on key transmission corridors.
- VELCO has standardized on this PST design to simplify operations and maintenance activities on key phase-shifter controlled transmission corridors.
- VELCO’s experience on its long-time phase-shifter controlled ties (i.e. PV20) is that the phase-shifter can easily become the limiting element in a circuit if insufficient rating margin is not provided in a long-lead, infrastructure-intensive power system element like a phase-shifting transformer.



Q. B-2 What is the reliability-based justification for increasing the phase shifting range of the PST being installed at Blissville Substation from $\pm 40^\circ$ to $\pm 60^\circ$? What was the incremental cost incurred to purchase and install the higher rated, wider phase angle PST over the PST originally proposed for Blissville Substation?

A. B-2. The reliability based reasons why the PST installed at the Blissville substation with a $\pm 60^\circ$ angular range instead of a $\pm 40^\circ$ include providing angular margin beyond that indicated in the reliability needs studies due to the following reasons:

- The design studies performed for the NRP for the Blissville PST and its angular range needs only examined system performance a few years into the future, as is consistent with current planning practice. This study practice does not account for lifetime angular needs of the PST.
- The unit installed at Blissville can replace the units at Sand Bar and Granite for an equipment failure scenario. These units need more than $\pm 40^\circ$.
- VELCO's experience has been that load growth, system stresses and unforeseen system needs commonly utilize PSTs taps and angular range beyond what is predicted in power flow studies over the lifetime of a PST-installation as we've experienced on our PV20 tie. VELCO's good utility & engineering design practice to purchase and install a PST with angular range margin on a key NY-NE transmission tie such as the Whitehall – Blissville line to deal with future, yet unforeseen operating conditions.

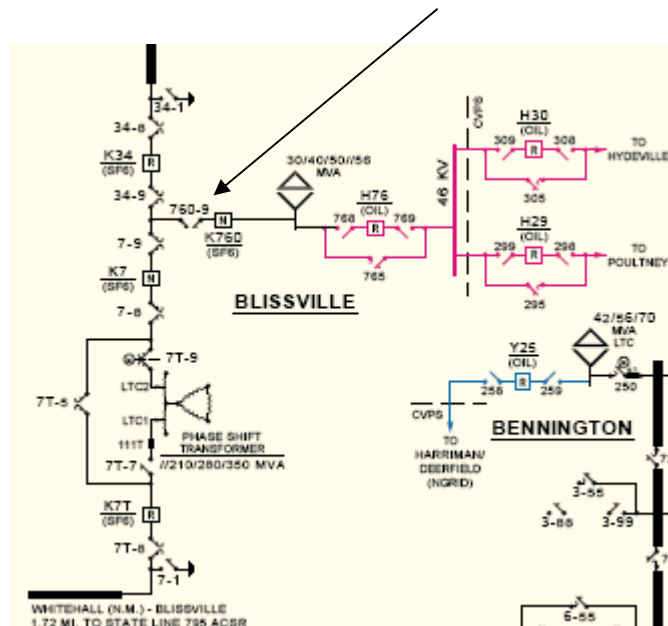
For the procurement of the PST for Blissville, VELCO did not solicit a transformer specification to meet only the $\pm 40^\circ$ range, hence VELCO cannot provide a definite response as to the incremental cost. However, based on the cost breakdown of this type of equipment, design, material, and freight, the design cost would have been higher (issue of a new design, estimated at approximately \$200K) and the other cost differences would be negligible. VELCO already had purchased and installed a $\pm 60^\circ$ PST for Sand Bar from a manufacturer that had provided a quality product, on-time and on-budget with timely and sound engineering support. VELCO chose to purchase additional PSTs from the same manufacturer to improve the delivery time and reduce cost by eliminating the need for an RFP (saving a few months of elapsed time) and the time needed to create a new PST design (an additional few months) if a new vendor were selected. ISO-NE's Planning and Operations groups had indicated that they wished to have the Blissville PST installed as quickly as possible and that the additional angular range was a desirable aspect of our PST's design.



Q. B-3 What is the reliability-based justification for adding one 115 kV breaker to the design of the Blissville Substation and what incremental cost was incurred to purchase and install the additional breaker?

A. B-3. The fourth 115 kV breaker at the Blissville substation, a non-PTF high-side breaker on the 115 / 46 kV Blissville transformer, was installed on the high-side of the transformer for both reliability and cost reasons. The fourth breaker is shown in the one-line below and is labeled K760. The reliability reasons were based on VELCO’s experience with the use of circuit switchers and circuit breakers for switching and fault interruption needs on its 115 kV to lower voltage transformers; the circuit breakers have demonstrated a significantly lower level of failures and misoperations than the circuit switchers, and operate faster under fault conditions. For the same or less cost, a 115 kV circuit breaker can replace a 115 kV circuit switcher and improve fault clearing, interrupting and load break performance.

The incremental direct cost for the purchase and installation of the additional 115kV/40kA is estimate to be \$85.3K (includes all associated direct & indirect costs – 2006 Costs), which was a non-PTF borne cost.





Q. B-4 Was the scope of work performed at the Williston Substation in agreement with Vermont Public Services Board's filing for Docket 6860? If the scope is different, please describe the associated cost and, from a reliability perspective, justify this scope change.

A. B-4. See Section A, answer to A-4



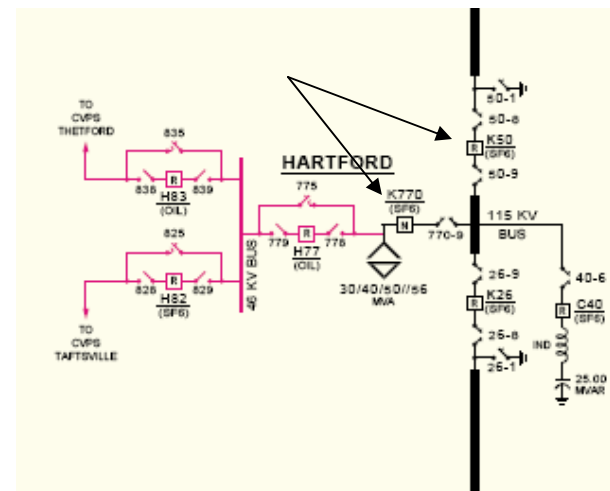
Q. B-5 Describe the reliability-based justification for installing a fourth 115 kV breaker at the Hartford Substation and provide the incremental cost for procuring and installing this breaker.

A. B-5. Two 115 kV breakers were included in the 2003 original TCA for the Hartford substation. Two additional breakers, either of which may be the “fourth 115 kV breaker” referred to in the question were added at Hartford. The breakers are the 115 kV line breaker protecting the K50, 115 kV line section looking toward VELCO’s Chelsea substation and a non-PTF high-side 115 kV breaker on the 115 / 46 kV Hartford transformer. The one-line below indicates the location of the two breakers in question.

The reliability reasons for installing the 115 kV K50 line breaker include retaining the 115/46 kV injection into the networked 46 kV subtransmission system for loss of the 115 kV line from Granite through Chelsea to Hartford as well as the 115 kV, 25 MVAR capacitor bank installed at Hartford. The cap bank supports local 115 kV voltage, while flow from the Hartford 115 / 46 kV transformer precludes voltage collapse on the underlying 46 kV subtransmission network. Due to the networked nature of this 46 kV system, a voltage collapse can extend to the Chelsea, Windsor, Ascutney, Cold River, Middlebury, and Bellows Falls substations with unpredictable results.

The reliability reasons for installing the high-side 115 kV circuit breaker (K770) were based on VELCO’s experience with the use of circuit switchers and circuit breakers for switching and fault interruption needs on its 115 kV to lower voltage transformers; the circuit breakers have demonstrated a significantly lower level of failures and misoperations than the circuit switchers, and operate faster under fault conditions. A failure of the high-side switching device to actuate correctly lead essentially to a Hartford bus fault, which opens the 115 kV corridor from Granite to Wilder to Ascutney / Bellows Falls, removes the Hartford 25 MVAR cap bank and potentially leads to unacceptably low local transmission voltages. Also, the existing circuit switcher was underrated for local short circuit levels.

The incremental direct cost for the purchase and installation of an additional 115kV/40kA breaker is estimate to be \$85.3K (includes all associated direct & indirect costs – 2006 Costs), which was a non-PTF borne cost.





C. The following questions are with respect to TCA application VELCO-03-155-02-RI

Q. C-1 Taking into consideration the change of scope for the PST at Granite Substation, what was the incremental cost associated with the redesign of Granite Substation over the original proposed design?

A. C-1. Design Evolution:

Original Filed Design:

- One Auto Transformer 336 MVA 230/115kV
- One 550MVA 230kV, 0/60 phase shifter
- Two 230kV Breaker (PST)
- 4 Position 230kV Ring Bus
- Expansion of Existing 115kV Ring bus to a 6 Breakers Ring Bus.
- Addition of 150MVAR DVD (Black Box)
 - **Implies** 2 Transformers (35-40MVA, 115kV to lower voltage)⁽¹⁾
- Four 24.75 MVAR 115kV shunt caps.

Project As-Built:

- Two⁽¹⁾ Auto Transformers 400 MVA 230kV/115kV/13.8kV.
- Two 350MVA 115kV⁽²⁾, +/-60 phase shifters
- Two 230kV Breaker (PST)
- 4 Position 230kV Ring Bus
- Expansion of Existing 115kV Ring bus to a 6 Breakers Ring Bus.
- Addition of 150MVAR DVD⁽³⁾ – 4x25MVA synchronous condenser
- Four 24.75 MVAR 115kV shunt caps.

Reasons:

- (1): The Existing 230kV auto was underrated based on 2003 pre blackout system event. The second transformer became then a project requirement to meet desired system operation rating. The tertiary voltage saved the need for 2 additional transformers as well as 115kV additional equipment (breakers, etc...) to accommodate these. This resulted in significant cost savings.
- (2): Design issue in regards to constructability. During the procurement process vendors did not have a proven working design, and expressed many concerns in regard to the unit size, design, constructability, operability and transport. This led to the alternate option, which performs better and provides better contingency coverage.



- (3): Based on the actual Handy Whitman Index costs from 1999-2006 (date of the contract with for the RPD), the escalation cost for the Statcom device compared to the RPD as built (\$22M) at the Granite Substation is as follow:
 - 1999 Bid: \$12.0M to \$19.0M – Assumed purchase cost was \$15.5M
 - 2006 Escalated: \$18.2M to \$28.8M – Assumed purchase price would be \$23.5M

This choice resulted in an estimated **\$1.5M+ saving**.

VELCO estimates the design evolution of the substation resulted in a more reliable, efficient and economic solution for the reliability issues addressed by this project.



Q. C-2 It would appear that the continuous availability of the four 25MVA fixed capacitor banks at Granite allows the four 25MVA synchronous condensers to remain off-line in stand-by mode all but approximately 10% of the hours of the year. Is this a correct technical assessment? If not, please describe further.

A. C-2. It is not a correct technical assessment. The voltage needs for the local system are dependent upon a number of variables, including transfers and flows, load level, system voltage profile, generation availability and output, NVI (Northwest Vermont Interface) and CVI (Central Vermont Interface) flow and system power factor. For example, VELCO has noted in multiple recent power factor compliance letters that VELCO needs utilize this facility at light load levels to maintain acceptable dynamic reactive reserves. VELCO believes that there will be a need to place on-line two of the four synchronous condensers most of the time for dynamic reactive needs for both light load periods and peak load periods (summer and winter – VELCO is a dual peaking area), as well as to keep dynamic capability on-line for immediate use of the Granite PSTs for operational needs when called upon. Having some of the sync condensers continuously on-line allows immediate use of the Granite PSTs as opposed to waiting for start-up and synchronization of the condensers, which may take many minutes. Finally, keeping two of the synchronous condensers continuously on-line (one on each transformer) minimizes voltage dip for the start of the third unit, and keeps some dynamic capability on-line for loss of either set of 230/115 kV transformer and PST.

The steady state studies undertaken for the NRP demonstrated the need for the 150 MVAR of dynamic range and did not provide enough information to suggest expected operational use. Subsequent operating studies, interface limit analyses and daily operational assessments of system voltage needs indicated it would be likely that a combination of static capacitors and a subset 25 MVA machines (two) will be needed to meet system reliability and operational needs normally. If further discussion is desired on this aspect of the installation, please contact Dean LaForest at (802) 770-6323.



Q. C-3 Originally a two-staged implementation of DRD equipment was planned. It appears now that all the DRD equipment has been or will be installed right away. What is the reliability-based justification for installing all DRD equipment right away and is there an economic justification for installing all the equipment right away?

A. C-3. VELCO did not install all of the RPD equipment right away. VELCO is installing only the first of two independent 150 MVAR dynamic devices (i.e., four +25 to -12.5 MVAR synchronous condensers). The original design called for two separate 150 MVAR dynamic devices (originally contemplated to be 2-75 MVAR STATCOMs each with 150 MVAR dynamic range). The existing site can be expanded to accommodate the second 150 MVAR device when the need arises. The reliability-based justification for the initial 150 MVAR device installation is based on the studies supporting the PPA.



Q. C-4 What was the original cost estimate for Stage 1 and Stage 2 DRD equipment and installation? What was the final cost for Stage 1 and Stage 2 DRD equipment and installation? What portion of the \$37.0 million variance should be allocated to:

- i. The difference between original and final DRD costs for both stages?*
- ii. The installation of Stage 2 DRD equipment early?*

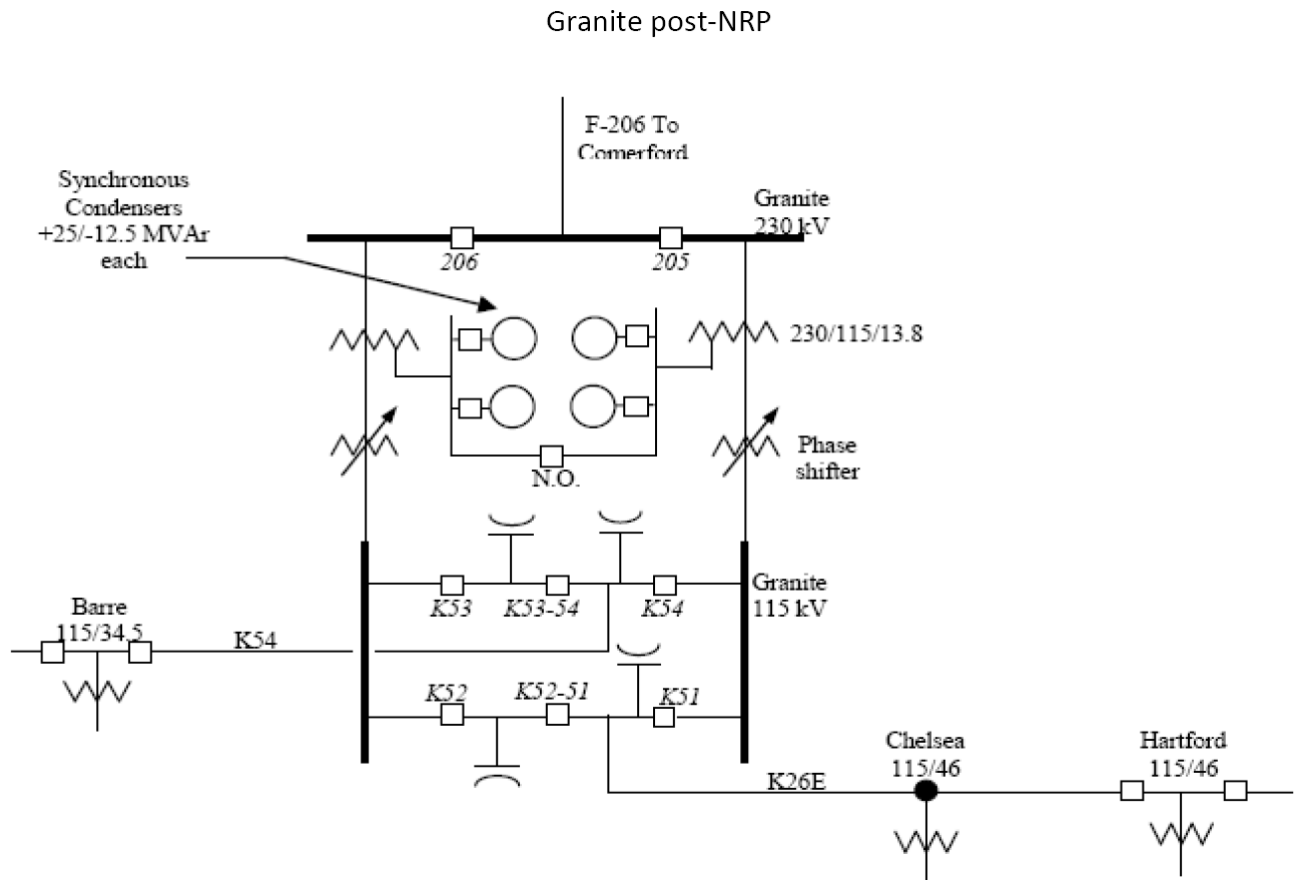
A. C-4. See Section C, answer C-1. The final cost for stage one is forecasted at \$22M (excluding AFUDC and the cost of the two (2) 115kV capacitor banks, approximately \$500K installed cost per unit), which includes the DRD equipment as listed in C-1. There was no early installation of any part of stage 2 equipment. The initially estimated cost of Stage 1 was \$15.9M. Therefore, the portion of the \$37.0 M variance due to a difference between original and final DRD costs for Stage 1 is \$7.1M ($\$22\text{M} + \$1\text{M} - \15.9M) and for Stage 2 no cost difference (no portion of Stage 2 has been installed).



Q. C-5 Identify, using a circle placed on the "Granite Post NRP One-Line Diagram" provided as the last page of the TCA VELCO-03-155-02 R1 package, what spare DRD equipment was (or will be) installed, including the incremental cost of this spare equipment and the allocation to PTF and non-PTF requested costs.

A. C-5. There is no equipment on the “Granite Post NRP One-Line Diagram” provided as the last page of the TCA VELCO-03-155-02 R1 that was or will be installed as spare equipment. The indicated figure from TCA VELCO-03-155-02 R1 is reproduced below for reference.

"Granite Post NRP One-Line Diagram" provided as the last page of the TCA VELCO-03-155-02 R1 package





Q. C-6 A \$37.0 million cost increase will be realized with the completion of Granite Substation. What portion of this \$37.0 million cost variance should be apportioned to the change in scope involved in procuring and installing two 400MVA three-winding transformers instead of one 300MVA two-winding transformer? Other than facilitating the connection of the 13.8 kV synchronous condenser DRD equipment, does this scope change provide incremental reliability benefits? If so, please describe.

A. C-6. At this time, we estimate \$5.0M out of the \$37.0M cost increase is to be attributed to the replacement of the under rated existing Granite autotransformer.

The original design assumed a single 336 MVA, 230/115 kV transformer. After the submission of the NRP 18.4 and 15.5 applications in late 2002 and early 2003, VELCO experienced a high loading event on the F-206 230 kV corridor the week before the August 2003 blackout. The existing 30 year old Granite 230/115 kV transformer experienced high oil temperature alarms and indications of heavy loading at loadings in only the 200+ MVA range, well below its nameplate capability. This event demonstrated that the existing Granite transformer would limit the use of the F-206 transmission corridor (with its 379 MVA LTE limit) even more than originally thought. This event led to the decision to replace the existing Granite 230 / 115 kV autotransformer with a second 336 MVA 230 / 115 kV unit that would not limit the use of the F-206 corridor for reliability purposes. Those purposes include responding to system needs for loss of the 340 line circuit during peak load levels as documented in the studies supporting the Southern Loop Project. The substation was designed to provide full F-206 corridor capacity for any single long-term outage of station equipment.

The dynamic reactive device (DRD) approved in the NRP in 2002/2003 was to be connected to Granite 115 kV ring bus with transformation to a lower voltage depending on the DRD selected. The design for the connecting this DRD to the 115 kV ring was not specified in the TCA or the PPA (section 18.4 application) at the time; the 18.4 approval from the Reliability Committee merely noted an approval for a “+/- 75 MVAR Dynamic Voltage Control Device with two 24.75 MVAR shunt capacitor banks (expandable to a +/- 150 MVAR control device with four 24.75 MVAR shunt capacitor banks)”. Our presumption at that time was to select a design, if a STATCOM was chosen, similar to that of the Essex installation. That installation included two transformers each connecting half of the STATCOM to the 115 kV grid. Therefore, the initially Granite design had the existing 230/115 kV transformer, a new 336 MVA, 230/115 kV transformer, and two 115 kV to lower voltage transformers. When assessing available



space at the Granite substation site and potential cost, VELCO determined that a valid transformation alternative was to consider the use of three-winding transformers – 230/115 kV banks with tertiary windings that could be used to connect the DRD. VELCO's technology assessment for the DRD had led to the selection of synchronous condensers with nominal output at 13.8 kV of +100 to -50 MVARs. To achieve a 100 MVA tertiary rating, a 400 MVA 230/115 kV transformer was required.

The incremental reliability benefits from this change in transformation are:

- Full F-206 corridor capacity is maintained for loss of either 230/115 kV transformer (which was not possible given the original proposal)
- Full DRD capacity is maintained for loss of either transformer through the use of the transformer tertiaries and 13.8 kV facility switching (this was not possible given the original design)

The Granite as-built transformation allows a future reconducting of the F-206 circuit to achieve significant added capacity with all facilities in-service. The need for this upgrade was identified in VELCO's 2006 Long Range Plan Analysis.



D. The following questions are with respect to TCA application VELCO-03-155-03-R1

Q. D-1 \$0.7million was expended as Localized cost to" ...reroute a 115kV line." Describe which 115 kV line was rerouted and explain why this line was rerouted.

A. D-1. The K30 line was rerouted to put it farther from Route 7 for Aesthetic reasons and place it along the revised 370 Line corridor. This change was ordered by the Public Service Board as part of the Vermont Post-Certification process. The 370 Line corridor relocation compared to the original design resulted in the addition of 3 additional angle structures and 1 tangent structure. The associated cost of the 345kV line corridor relocation and the cost of the 115kV line relocation were qualified as localized (non-PTF) costs.

	Total Cost	Comments
115kV line Reroute	\$ 0.70	115 kV Structure relocation
345 kV Alternative Incremental Cost	\$ 0.20	3 Additionnal Angle Structures, 1 Additional Tangent
Total Localized PTF	\$ 0.90	

Details information as provided in prior NRP cost update presentation

See attachment 1 for the line corridor revised location



Q. D-2 \$0.2 million was expended as Localized cost"... for additional angle and tangent structures for the 345 kV line." Explain why these additional structures were added to the project.

A. D-2. These additional structures were added to the project to construct the 370 line in the alternate ROW which resulted in added line length from the original proposal. The additional angle and tangent structures addressed the added line length and the requirements of constructing the 370 line in the alternate ROW. Please also see Section D, answer to D-1 and the attachment.



Q. D-3 Table 1 contains the difference between the original and revised TCA application for both the New Haven Substation and 345 kV line from the West Rutland substation to New Haven substation. Indicate all cost drivers and provide a description of why that was a cost driver.

A. D-3. Here is the cost drivers associated with each component:

	Cost Difference between the Original TCA and Revision 1		Cost Driver(s)	Description of Cost Driver(s)
	New Haven Substation	345kv Line from the West Rutland to New Haven Substations		
Materials	\$4.5M	\$5.0M	Escalation	<i>See NRP cost update Presentation as provided to the stakeholder meeting</i>
Labor and Construction Equipment	\$4.5M	\$20.6M	Escalation Adverse Weather Impact Underestimated equipment cost.	<i>See NRP cost update Presentation as provided to the stakeholder meeting for details.</i>
Engineering, Design and Permitting	\$2.6M	\$4.7M	Escalation Underestimation	<i>Planning Grade estimate underestimated the level of effort required for engineering & Permitting</i>
Right of Way	\$0.417M		Underestimation Relocation of the substation	<i>Planning Grade estimate underestimated for the original site. Request from the Vermont PSB to relocate the substation at a different location⁽¹⁾</i>

(1): See Section A, answer A-4 for further details



E. The following questions are with respect to TCA application VELCO-03-155-04-R1

Q. E-1 As a Post Certification Submittal, it was noted that VELCO was required to revise its original Design Plans and also revise the Aesthetic Mitigation Plans for the 115 kV circuit between the New Haven and Queen City substations in the time period between April and June 2006. Explain who requested these design changes, the nature of the revision and what cost was expanded for the revision.

A. E-1. The Vermont Public Service Board examined siting for the elements of the NRP during and after section 248 process. The post-certification review process included additional siting review efforts by the Board, the Department of Public Service and VELCO with affected and impacted stakeholders along the corridor for the 115 kV line between New Haven to Queen City. It was during these efforts that VELCO received additional comments from these affected and impacted stakeholders and the statutory parties on its Design and Aesthetic Mitigation Plans for the 115 kV New Haven to Queen City circuit. These requests were common to investigate pole height reductions using acceptable design changes that still met VELCO's line design requirements. Requests by the City of Vergennes, the Town of Shelburne, the Nature Conservancy, the Department of Public Service, various landowners and VELCO's aesthetic consultant were considered. VELCO examined each of these requests and accommodated those changes that achieved an appropriate balance between cost, line design requirements, aesthetics and stakeholder needs. The design changes resulting in general pole height reductions cost \$245,000 while the changes to the aesthetic mitigation plans resulting from consideration of the requests resulted in costs totaling approximately \$100,000.



Q. E-2 As a Post Certification Submittal in August 2006, there was a request made to study and formulate cost estimates for placing certain portions of the 115 kV circuit underground. Were the costs for these studies and cost estimates made part of the cost incurred to install the Queen City to Shelburne and Charlotte to North Ferrisburg 115 kV underground circuit segments?

A. E-2. The project was re-estimated in 2005 including the newly proposed underground section. Since this was part of a larger effort for re-estimating the project, the costs for the undergrounding estimate were not specifically separated. This is true for the studies which were part of the permitting and line siting process. These indirect costs are not specifically part of the underground section but were allocated according to the underground vs. overhead direct cost (as part of the weighted average split of the cost per mile for underground vs. overhead as presented in the table in Section E, answer to E-4).



Q. E-3 In the above Post Certification Submittal, a reference was made to placing a portion of the new 115 kV circuit underground between the Shelburne and Queen City substations and Charlotte and North Ferrisburg substations. Were there any costs, not captured in the cost estimates related to question 2 above, for underground termination facilities located at the Shelburne and North Ferrisburg substations? If so, identify these facilities and their costs exceeding what would be incurred to install overhead termination facilities.

A. E-3. There are no underground termination facilities at these substations. These transition structures are part of the line segments except for one which take place at Charlotte substation. The associated cost of the transition poles are part of the cost of the undergrounding line sections and will be treated as Localized PTF (incremental cost). The same approach holds true for the termination facilities at the Charlotte Substation.



Q. E-4 A "differential cost" of \$9.7 million was identified for 1.73 miles of underground construction from the Queen City to Shelburne substations. Provide the absolute cost of this underground circuit segment, where the breakdown of the cost is allocated between the following six categories: Labor, Materials, Engineering Design and Permitting, ROW, AFUDC and Indirect. Also indicate how much of this cost is allocated to the spare 115 kV ducts installed as part of this underground system. How much of this cost is allocated to the spare cable installed as part of this segment? How much was the per-unit cost of overhead construction which was assumed as part of the "differential cost" and how was this per-unit overhead cost determined?

A. E-4. As presented to the stakeholder meeting on May 30th, 2008, the allocation for cost of non identifiable overhead vs. underground costs items was made on a weighted average of direct costs for all the remaining costs. Since the project has not been completed at this time, a final cost allocation cannot be determined prior to the asset value being evaluated. Nevertheless, the table below reflects our best estimate at this time of a cost per mile of the underground vs. the overhead option for the various cost categories.

Using a weighted average estimate, costs for Right of Way are different between the underground and the overhead versions. These will be adjusted upon completion of the project during the unit costing phase of the project.

Line Cost per Mile (\$ in thousand)	N. Haven to Queen City (115kV OH) - Forecast	N. Haven to Queen City (115kV UG) - Forecast
Material	\$ 206	\$ 2,093
Construction Labor & Equipment Include Clearing	\$ 381	\$ 3,139
Engineering & Design	\$ 147	\$ 164
Project Management (Inc. Overhead)	\$ 295	\$ 330
Permitting (Including Legal Expenses)	\$ 191	\$ 214
Right of Way	\$ 436	\$ 488
AFUDC	\$ 189	\$ 211
Total Inc. HW Adjustment	\$ 1,844	\$ 6,639

(Values in thousands)



Based on the quotes for the project, the anticipated cost for the underground duct bank (included in the above table under Material, Construction Labor & Equipment costs) are about \$630,000 per mile since 3 conduits out of the 6 are spares, under a simplified approach, half of this cost (or \$315,000) is for the spare. This approach is consistent with good utility practice planning for future expansion.

The cable cost per mile is about \$2,621,000 per mile, since there is one extra wire, 25% of that cost or \$655,000 is the forecasted cost for the spare cable (including installation labor cost).



Q. E-5 Similarly, a "differential cost" of \$2.9 million was identified for 0.44 miles of underground construction from the Charlotte to North Ferrisburg substations. Provide the absolute cost of this underground circuit segment, where the breakdown of the cost is allocated between the following six categories: Labor, Materials, Engineering Design and Permitting, ROW, AFUDC and Indirect. Also indicate how much of this cost is allocated to the spare 115 kV ducts installed as part of this underground system. How much of this cost is allocated to the spare cable installed as part of this segment? How much was the per-unit cost of overhead construction which was assumed as part of the "differential cost" and how was this per-unit overhead cost determined?

A. E-5. See Section E, answer to E-4.



Q. E-6 A Post Certification Submittal shows the original Design Plan and Landscape Mitigation plans for the Vergennes Substation were revised. Who requested these Design Plans and Landscape Mitigation Plan revisions be made and what was the nature of the revision? Also, what costs were incurred for the revision of the Design Plans and Landscape Mitigation Plans at the Vergennes Substation?

A. E-6. The original site was space constrained and could only accommodate the original substation with significant difficulty. A better suited site, with better system performance, was established with interconnectivity to the 34.5kV sub-transmission system. The changes in the substation design as part of the design evolution are outlined below and total an incremental PTF cost of \$230K and a shared PTF/non-PTF cost of \$250K (Original common allocation ratio estimated at 74% PTF and 26% Non-PTF):

- Changes requested by VELCO:

- *Added one 115kV Breaker to eliminate circuit switcher.*

Reason: The original design required a total of three 115 kV circuit breakers and two 115 kV circuit switchers. The proposed design eliminates the circuit switchers and requires four 115 kV circuit breakers. In addition, the resulting design is more reliable than the original design.

Incremental Cost: None

- *Added one (1) additional transformer position*

Reason: For present protective relaying and control scheme. The original filing included three phase potential transformers in locations where single phase transformers are presently required resulting in two (2) less potential transformers required overall, however the present relay scheme requires three (3) potential transformers, not originally identified, with a net result of one (1) additional potential transformer required for the present relay scheme.

Incremental Cost: Estimated \$115K for the additional breaker (including direct & indirect cost).

- *New Control house vs. expansion of the existing control house at the original site 24' X 30' to 32' X 48'.*

Reason: Substation relocation & requirement by NESC standard clearance from electrical equipment and safe working distance.



Incremental Cost: *Estimated: \$250K.* Will be refined during the asset unit costing stage (This does not include productivity gain with building new controls house vs. expanded the existing one)

- *Removed one (1) 75' Shield Mast.*

Reason: Grounding & lightning shield analysis determined that the mast is not required to meet the VELCO requirements for lightning protection of substation equipment.

- *Landscape Mitigation Plans revised*

Reason: Accommodate the footprint of the revised substation.

Incremental Cost: No incremental cost is forecasted.

- Changes requested by Public Service Board:

- 34.5kV sub-transmission service within the new site & associated design upgrades.

Change to Low Profile Tubular Ring Bus with four position (vs Steel Lattice Towers)

Reason: Lower Aesthetic impact.

Incremental Cost: None.

VELCO initially proposed modifying Green Mountain Power's (GMP) existing Vergennes's substation to accommodate the new 115 kV line. This site was originally chosen because it was located on the existing 46kV and 34.5kV line corridor. The site was a very difficult location to work in. It was extremely constrained and located within approximately ten feet of the Otter Creek. The GMP substation site is approximately 90 years old and is located at the foot of a dam within the Otter Creek basin, a historically significant area. VELCO would have had to relocate a historic structure to fit the new station in and may have had to use GIS equipment due small available footprint. Finally, work at the originally proposed location would have had to be done within a very tight, energized substation. In response, in part, to these concerns, in February of 2004 VELCO proposed the Vergennes reroute. The reroute included the construction of a new Vergennes substation at a greenfield site that provided adequate space for the construction and did not require work in or near energized equipment. The new site reduced labor construction cost due to improve productivity and access and reduced the overall length of the 115kV line by about 1 mile.



Q. E-7 The Vermont Public Service Board Findings for Docket 6860 specify the following for the new Vergennes Substation: 1) Three new 115 kV circuit breakers arranged to accommodate an ultimate four-breaker ring bus, and 2) one new 115 kV/34.5 kV, 30MVA transformer. Further revised TCA application indicates that the following has or will be installed: 1) four 115 kV circuit breakers arranged in a ring bus configuration and 2) two new 115 kV/34.5 kV. What alternatives, for example on the 34.5 kV sub-transmission system, were evaluated before expansion of the 115 kV facilities at the 30MVA Vergennes Substation was undertaken?

A. E-7. The alternatives were to supply Vergennes from the North or South at a subtransmission voltage (34.5kV or 46kV) to provide a backup to a sole 115kV to 34.5kV transformer at Vergennes. The ROW used for the 115kV line between New Haven through Vergennes to Queen City required removal of most portions of the existing substation circuits. Therefore, use of either alternative would require not only substation additions to the North (North Ferrisburg or further) or South (New Haven) but also the construction at least 5 miles of subtransmission line. Given the cost of these added facilities, the need to acquire new ROW to construct these new miles of line, and the relative ease and low cost to fill in the remaining breaker position at the Vergennes substation and install a second 115kV to 34.5kV transformer, this latter alternative was the logical choice.



Q. E-8 A cost increase of \$5.0 million is shown for the Vergennes Substation. What portion of both PTF and Non-PTF cost increases should be allocated to the expansion of the 115 kV Vergennes Substation?

A. E-8. As mentioned in other NRP Cost presentations the cost increases are a combination of design revisions and cost escalation. Vergennes substation 115kV design expansion based on the new site location and the low side configuration, resulted in:

- For PTF Facilities:
 - Expansion of the originally proposed (2) 115kV breaker to a (4) 115kV breaker ring bus.
Incremental Cost: Estimated \$200K for steel, \$420K for associated additional foundations.
 - The addition of two (2) additional 115kV breakers on the high side which has an estimated cost of \$115K per Breaker.
Incremental Cost: \$230K total (includes all associated direct & indirect costs – 2007 Costs)
- For Non-PTF Facilities:
 - Procurement of a 115/34.5kV transformer 30MVA (vs. 115/12.4kV, 20MVA)
Incremental Cost: \$70K (115/34.5kV, 30MVA unit was \$625K vs. \$555K for the 115/12.4kV, 20MVA unit)
 - Addition of one 34.5Kv Breaker and associated equipment
Incremental Cost: Estimated \$50K.

However, due to the factors noted in response to question E-6 (very constrained historic site, close proximity to water and energized equipment), the relocation of the Vergennes substation actually saved money when compared to what it would have cost to build in the originally proposed location.



Q. E-9 A Post Certification Submittal in August 2006 revised the original Design Plans and Landscape Mitigation Plans for the Shelburne Substation. Who requested these Design Plans and Landscape Mitigation Plan revisions be made and what was the nature of the revision? Also, what costs were incurred for the revision of the Design Plans and Landscape Mitigation Plans at the Shelburne Substation?

A. E-9. VELCO requested the following changes:

- *Substation Relocation.*

Reason: Space limitation and risk associated with working near energized equipment in the existing substation.

- *Underground Distribution Feeders*

Reason: Reduced Aesthetic Impact

Incremental Cost: Estimated \$492K (Non-PTF)

- *The two 115 kV tubular steel dead-end structures have been replaced with a box structure.*

Reason: The original design for the Ferrisburg, Charlotte and Shelburne Substations did not allow space or connection points for a 115 kV – 12.47 kV mobile substation. The GMP 12.47 kV distribution system from each of these substations is essentially radial, with limited or no ties to adjoining substations. In the event of a transformer failure, a mobile substation is required to provide backup service. In addition, the original layouts did not provide sufficient space for maintenance access. The proposed design allows for a more compact 115 kV switching structure, which leaves more space for maintenance access and for the mobile substation. For economy and cost efficiency, the three substations were designed to utilize a common structure type. Note that the structure is a “box” structure, but the columns are intended to be solid structural steel, not lattice. The structure is relatively light duty, with line tension supported by guyed structures outside the substation.

Incremental Cost: None

- *The 115 kV circuit switcher has been replaced with a 115 kV circuit breaker.*

Reason: Refer to prior reference to the substitution of this equipment. See Section A, answer A-4.

Incremental Cost: None

- *Remove (1) 60-foot lightning shield mast*

Reason: Grounding and Lightning shield analysis determined that shield masts are not required to meet the VELCO standard for protection of equipment in the substation.



Q. E-10 A Post Certification Submittal was required to study and develop "incremental cost estimates" for an alternative location and/or design of North Ferrisburg Substation. Who requested that the alternatives be studied? What was the nature of revision to the North Ferrisburg Substation that was ultimately adopted? What costs were incurred for study/cost estimate preparation and for subsequent location/design changes for this location?

A. E-10. The Public Service Board directed VELCO to study an alternative location for the Ferrisburg substation. As a result of this study, the PSB approved the substation relocation. As a result of the proposed new site, the following aspects of the substation design were changed, with a total incremental cost of \$505K shared between the PTF and non-PTF (Original common allocation ratio estimated at 55% PTF & 45% Non-PTF) and non-PTF cost of \$238K:

- *Acquire Land for the new site.* Note that the original site & associated parcel needed for the expansion of the existing substation was federally protected conservation land and were not available to VELCO for either purchase or condemnation. This made the relocation a necessity.

Cost of the land: \$475K including legal fees and indirect cost. This is a common cost shared between PTF and non-PTF.

- *Adding approximately 500' of access road from Longpoint Rd to new site.*

Incremental Cost: Estimated \$5K. This is a common cost shared between PTF and non-PTF.

- *Substation fence perimeter area will be 110' X 225' and is approximately 0.6 acre*

Incremental Cost: Estimated \$25K. This is a common cost shared between PTF and non-PTF.

- *New steel structures to support bus work, regulators, re-closer, station service transformers, disconnects, mobile substation connection and riser structure for buried distribution feeders to Longpoint road for the 12.47kV portion of the yard to accommodate the relocation of the GMP facilities.*

Incremental Cost: Estimate \$40K (Non-PTF)

- *Underground Distribution Feeder*

Reason: Reduced Aesthetic Impact

Incremental Cost: Estimated \$198K (Non-PTF)



Q. E-11 A Post Certification Submittal shows the original Design Plan and Landscape Mitigation plans for the Charlotte Substation were revised. Who requested these Design Plans and Landscape Mitigation Plan revisions be made and what was the nature of the revision? Also, what costs were incurred for the revision of the Design Plans and Landscape Mitigation Plans at the Charlotte Substation?

A. E-11. No changes have been made to the Landscape Mitigation Plan at this time.

The changes in the substation design as part of the design evolution were, with a total incremental cost of \$150K shared between PTF and non-PTF (Original common allocation ratio estimated at 55% PTF & 45% Non-PTF) and non-PTF cost of \$705K:

- Changes requested by VELCO:
 - *Underground 115kV feeder.*
Incremental Cost: Estimated \$50K for Undergrounding & \$20K (E&D) (Non-PTF)
 - *The two 115 kV tubular steel dead-end structures have been replaced with a box structure.*
Reason: See Section E, answer to E-9.
 - *115kV Circuit Switcher changed to 115kV Breaker.*
Reason: Refer to prior reference to the substitution of this equipment. Refer to the Section A, answer to A-4.
Incremental Cost: None
 - *Remove (2) 60-foot lightning shield mast*
Reason: Grounding and Lightning shield analysis determined that shield masts are not required to meet the VELCO standard for protection of equipment in the substation.
 - *Control house has been revised from 20' X 30' to 15' X 45'*
Reason: Required by NESC standard clearance from electrical equipment and safe working distance.
Incremental Cost: Estimated \$150K (PTF, and includes all associated direct & indirect costs). This does not include cost savings associated with increased productivity gains by building a new control house vs. expanding the existing one.
 - *Underground Distribution Feeder*
Reason: Aesthetic Impact.
Incremental Cost: Estimated \$655K (Non-PTF)



Q. E-12 A Post Certification Submittal in July - August 2006 indicates the revision of the original Design Plans and Landscape Mitigation for the Queen City Substation. Who requested these Design Plans and Landscape Mitigation Plan revisions be made and what was the nature of the revision? Also, what costs were incurred for the revision of the Design Plans and Landscape Mitigation Plans at the Queen City Substation?

A. E-12. No changes have been made to the Landscape Mitigation Plan since original plans were issued in 2006.

The changes in the substation design as part of the design evolution were:

- *Control house has been expanded from 28' X 80' to 32' X 80'* and design revised in order to meet the required NESC clearances for electrical equipment and safe working distance.

Reason: Required by NESC standard clearance from electrical equipment and safe working distance.

Incremental Cost: Estimated \$50K (shared cost between PTF and Non-PTF - includes all associated direct & indirect costs). This does not include cost savings associated with increased productivity gains by building a new control house vs. expanding the existing one.



Q. E-13 In the revised TCA application (ppl, Section 2), it is not clear from the description whether the "... two load serving transformers (one into a 34.5 kV sub-transmission network) ..." are new transformers or simply a reconnection of the existing transformers. Please provide a clarification of this description.

A. E-13. Two transformers are existing have been in-service at the Queen City substation for a number of years. There has been a 115kV to 34.5kV, 56 MVA transformer connecting the 115kV system to the undying 34.5kV subtransmission network and a 115 kV to 13.8kV transformer supplying the Burlington Electric Department since the station's construction in the 1970s. The Queen City substation work envisioned re-connecting the existing transformers. During the course of the Queen City construction work the 115kV to 13.8kV transformer failed. A new 115kV to 13.8kV transformer has been ordered and placed into service at the Queen City substation. Only two energized, non-PTF transformers are connected at the Queen City substation.



ATTACHMENT 1

