

# *International Review of Electrical Engineering (IREE)*

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# A Framework to Quantify the Economic Benefit from Local VAR Compensation

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**Abstract** – It is generally accepted that reactive power (or Var) compensation will bring benefits for utilities and industrial customers by providing local voltage and power factor support. However, there is a lack of a systematic approach to quantitatively identify the economic benefit. In addition, with deregulation and restructuring, it is important to indicate the amount of benefit that each market participant may potentially receive given the right price signals. If such information can be easily obtained and presented, it will be more convenient for decision-makers to determine the cost benefit sharing of installing a Var compensator. The vision of this paper is to lay out a possible method for quantitatively evaluating the benefits from local reactive power compensation. The approach is to quantify the benefits into several categories such as reduced losses, shifting reactive power flow to real power flow, and increased transfer. The calculation of these benefits are illustrated with a simple two-bus power system model and then presented with a more complicated model using Optimal Power Flow to calculate the benefits. Simulation on the more complex system is conducted with seven buses in two areas. The simulation results show that the possible economic benefits can be significant, if compared with capacity payments to central generators or payment of power factor penalties applied by utilities. The potential economic value of local Var compensation may give various parties in electricity supply, delivery and end-use consumption a better understanding of the Var benefits to assist their cost-benefit analysis for Var compensation installation. Sensitivity analysis is also provided to illustrate that the benefits may not be monotonically increasing. Also, this paper suggests that the future reactive power market should consider local Var providers or other way to encourage load Var capability, since local Var benefit is significant. **Copyright © 2008 Praise Worthy Prize S.r.l. - All rights reserved.**

**Keywords:** Reactive power, Var compensation, Economic benefits, Transfer capability

## I. Introduction

The US power industry has been under great pressure to serve load economically since restructuring was first initiated over a decade ago. There has been significant movement towards competitive energy markets. However, reactive power, a critical need for power system operation, has received less attention until most recently due to the Great Northeast Blackout in August 2003 which pointed to the lack of reactive power production and delivery contributing to this major event. Several study initiatives by utilities, independent system operators (ISOs), and the government have addressed the reactive power issue. FERC has issued a staff report on the reactive power market both in the U.S. and internationally [1]. The Department of Energy sponsored a study by the Oak Ridge National Laboratory to investigate the economic benefits of local reactive power compensation, which is generally considered the most efficient means to provide reactive power since it does not travel well over long transmission lines [2]. For these reasons and due to the increasing need for power quality and transient stability,

dynamic Var compensators have received greater interest and attention since they can also provide local Var support [3]-[9]. These compensators include pure Var compensators, such as synchronous condensers, Static Var Compensators (SVCs), STATCOMs, as well as distributed energy resources (DERs) which can be generator-based, such as reciprocating gensets, or inverter-based, such as fuel cells and microturbines. Several previous works have discussed the cost [2] and the technical benefits [3]-[6] of dynamic reactive power compensation. However, the capital and operating cost of local dynamic Var sources is unfortunately high, and there is a lack of a standard method to evaluate the true economic benefits from these dynamic Var compensators. These challenges, along with an underdeveloped reactive power market make it difficult to economically justify the installation and operation of Var sources. In order to address this issue, this paper presents a possible quantitative approach to assess the “true and hidden” benefits of local Var sources at the demand side. The results from the application of this approach show some significant savings on the total system production cost and economic benefits to load-

serving utilities as well, which may increase their interest in local Var installation and further influence the decision-making process in favor of local Var compensation.

Estimating the benefits of the local Var compensation can be quite complex. As a reference and comparison, the capacity payment to central generators from ISOs may be used as a rough evaluation of the value of local Var compensation, because more local Vars means less Var capacity from central generators. Various ISOs in the US provide payments in the range of \$1,000 to \$4,000/MVar-year to generators with reactive capability. Another viewpoint of Var value is the penalties that may be applied to some US power utilities. The penalties are set by the transmission companies or system operators to ensure that distributors meet the minimum power factor requirement. The power factor penalty cost may be passed on to customers. The data among nationwide utilities shows that the typical penalty is about \$0.10/kW-month if the power factor is out of a required range[2], which may be translated to a few thousand \$/MVar-year depending on the required power factor and the present low power factor. Despite the above two approaches for rough estimation of local Var value, they do not truly represent the full economic benefits of the local Var support. Therefore, a more systematic approach is developed to find the benefits of local Var compensation.

In this paper, the economic benefits from Var sources are discussed through a systematic, quantitative approach. This makes it different from previous works [3-6] that qualitatively acknowledge the general benefits from reactive power, but no systematic approach was presented for economic study. Certainly, it is not possible to translate all benefits (some intangible) into monetary value or dollars. However, the method developed in this paper does present a systematic approach to quantify some, if not all, of the important benefits from Var compensation in dollars. In the discussion that follows, these benefits are classified into three categories. A market-based economic dispatch is employed for analysis since the U.S. power industry is moving towards system operation and control by independent system operators. This means that the dispatch may change with the connection and operation of local Vars. Certainly, different entities may have different variations of revenue streams, compared to the case without compensation. Therefore, the proposed framework of benefit classification and quantification may be used to allocate the investment cost of the local Var compensators.

This paper is organized as follows. Section II illustrates the possible benefits from local Var compensators using a simple two-bus system. Section III presents a more rigorous approach using economic dispatch to identify the benefits in three categories. Section IV presents the test results for a seven-bus system with local Var compensation. Section V provides

the results of a sensitivity analysis, and Section VI presents the conclusions.

## II. Benefits from a Var Source in a Two-Bus System

The economic benefits from local Var compensation are classified into three categories and discussed in detail in this section. It is important to point out that the economic benefit may have a positive or negative impact financially on different market participants, although the overall benefit is positive. To make it easy to understand these benefits, a simple two-bus system (Fig. 1) is used to illustrate the systematic methodology for capturing the hidden benefits for a generation area supply to a load area. In Fig. 1, there is a generation bus, a load bus, and a line connecting the two buses or areas. The generation bus represents a generation center consisting of an equivalent, low-cost unit at the rate of \$20/MWh. The load bus represents a load center, consisting of an expensive unit such as a gas turbine unit owned by an independent power producer (IPP) at the cost of \$25/MWh and an equivalent load serving entity (LSE) to serve all loads. The line represents an inter-tie or an interface between the two areas. The tie line is subject to the maximum transfer capability between the two areas and the tariff charged by the transmission owner (TO) which in this case is \$1/MWh.

The participants of the system shown in Fig. 1 are roughly classified as the four entities below:

- Local Load Serving Entity (LSE)
- Local expensive Load Center Unit (LCU)
- Low-cost Generation Center Unit (GCU)
- Transmission Owner (TO).

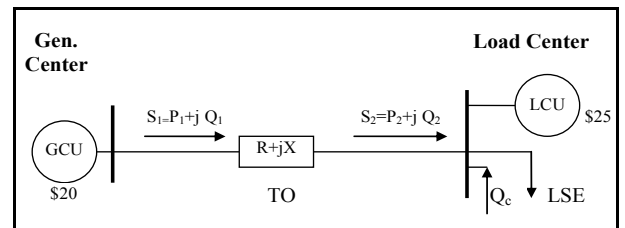


Fig. 1. A two-bus system

If we assume a load of 127.67 MVA (120MW, 43.59MVar) and the LCU generation dispatch of 30MW, then the net load of the Load Center is 100 MVA (90MW, 43.59MVar) with 0.9 lagging power factor. This implies an import of 90 MW and 43.59 MVar ( $P_2$  and  $Q_2$ , respectively) from the GCU through the tie line. The other parameters are as follows: the power base is 100 MVA; the voltage at the GCU bus is fixed at  $1.0\angle 0^\circ$  per unit; and the line impedance is  $0.02 + j0.2$  per unit. It is assumed that the local compensation device ( $Q_c$ ) will constantly inject 14.01 MVar to correct the load power factor to 0.95 and changes the import

reactive power requirements of the load center, i.e.,  $Q'_2 = Q_2 - Q_C = 43.59 - 14.01 = 29.58$  MVar.

II.1. Benefit from Reduced Losses (B1)

Injection of reactive power at the receiving end reduces the reactive power through the tie line and therefore reduces the line current and along with it the losses. Since the real power loss is  $I^2R$ , the losses will be reduced by the square of the current reduction. Going on the basis that the load-side voltage magnitude remains unchanged and very close to 1.0, the line loss and the power at the delivery end before compensation ( $Q_C=0$ ) are given as follows:

$$P_{loss} = I^2 R = \frac{P_2^2 + Q_2^2}{V^2} R = \frac{0.9^2 + 0.4359^2}{1.0^2} \cdot 0.02 = 0.02 \text{ p.u.} = 2 \text{ MW} \quad (1)$$

$$P_1 = P_2 + P_{loss} = 90 + 2 = 92 \text{ MW}$$

After  $Q_C$  is connected, the power losses and delivery end power are as follows (eq: (2)):

$$P'_{loss} = I'^2 R = \frac{(P'_2)^2 + (Q'_2)^2}{V^2} R = \frac{0.9^2 + 0.2958^2}{1.0^2} \cdot 0.02 = 0.018 \text{ p.u.} = 1.80 \text{ MW}$$

$$P'_1 = P'_2 + P'_{loss} = 90 + 1.80 = 91.80 \text{ MW}$$

Therefore, the total loss savings at the delivery end is 0.2 MW (92-91.8) or a 10% reduction of the original 2 MW losses for every 14.01 MVar compensation at the load center. This loss reduction represents reduced total generation. Certainly, the actual loss reduction may be a little less or more depending on the load voltage V and the level of Var compensation. Although the 0.2MW loss reduction is not a big MW savings, it can generate considerable cost savings when the loss reduction is stretched to every hour of the year (a total of 8760 hours). If this is the case, the annual savings will be \$35,040/year (= \$20/MWh × 0.2MW × 8760hr) if the same load is assumed for every hour. Obviously, the savings could be less or more depending upon how the load changes from hour to hour. The savings in dollars per MVar-year using the previous total and the level of compensation is \$2,501/MVar-year (= \$35,040/yr/14.01 MVar).

Based on the above analysis, it is clear that the LSE will pay less due to the line loss reduction, while the low-cost GCU will have reduced revenue because it delivers less power due to reduced losses. Also, the expensive LCU should not be impacted financially and the TO shall have reduced benefit if the transmission tariff is based on the sending end real power flow. Although different parties may have different impact

from Var compensation, the total system production cost will be decreased due to reduced losses. This is desirable from the viewpoint of overall system efficiency. Table I below shows the economic benefit in a generic formulation, where a positive sign represents economic gain and a negative sign represents an economic loss.

TABLE I  
ECONOMIC IMPACT TO THE VARIOUS ENTITIES  
DUE TO THE REDUCED LOSSES,  $B_1$

Participant	Economic Impact ( $B_1$ )	Impact Type
LSE	$B_{1,LSE} = C_{GCU} \cdot \Delta P_{loss} + T \cdot \Delta P_{loss}$	Reduced payment
GCU	$B_{1,GCU} = -C_{GCU} \cdot \Delta P_{loss}$	Reduced revenue
LCU	0	None
TO	$B_{1,TO} = -T \cdot \Delta P_{loss}$	Reduced tariff revenue
Production Cost	$B_{1,PC} = C_{GCU} \cdot \Delta P_{loss}$	Reduced total production cost

where:

- $B_1$  = the benefit from reduced loss;
- $C_{GCU}$  = the cost of the low-cost Generator Center Unit;
- $T$  = the tariff collected by the Transmission Owner;
- $\Delta P_{loss}$  = the reduced loss.

II.2. Benefit from Shifting Reactive Power Flow to Real Power Flow (B2)

The previous case assumes a fixed dispatch at LCU, which may be explained as a long-term MW contract. If re-dispatch is allowed, more low-cost power may be delivered from GCU to the load center and less power output from LCU. Here we assume that the tie line has a transfer limit that happens to be 100MVA, the same as the flow without compensation. Although this assumption is mainly for analytical purposes, this could correspond to a real case due to some limiting factors such as line thermal rating, the rating of a connecting transformer, or a series compensator rating.

Since the reactive power flow ( $Q_2$  to  $Q'_2$ ) has been reduced from 43.59MVar to 29.58 MVar due to local compensation, this makes it possible to have more real power delivered from the lower-cost GCU while the 100 MVA limit is not exceeded because of  $P_2 = \sqrt{S_2^2 - Q_2^2}$ . This benefit of transferring more cheap real power over the tie-line while keeping the same transfer limit is classified as the benefit of shifting reactive power flow to real power flow, or  $B_2$ , as in the title of this subsection. The new real power that can be transferred over the tie-line is given as:

$$P_2 = \sqrt{100^2 - (Q_2 - Q_C)^2} = \sqrt{100^2 - 29.58^2} = 95.52 \text{ MW} \quad (3)$$

Hence, the additional deliverable real power is 5.52 MW. Ignoring the small additional loss due to the 5.52

MW, this is the amount of additional lower-cost real power that can be delivered from GCU to the load center. Therefore, the total system production cost will be equal to the 5.52 MW times the price difference between the two generators, or \$27.60/hr. After deducting \$1/MWh tariff, the economic benefit to the LSE will be the reduced payment which is equal to \$22.08/hr ( $=\$27.60-\$5.52 \times 1$ ). The GCU will have an increased revenue of \$110.40/hr ( $= 5.52\text{MW} \times \$20/\text{MWh}$ ). The LCU will have a decreased revenue of \$138.0/hr ( $=5.52\text{MW} \times \$25/\text{MWh}$ ). The TO will have an increased revenue change of \$5.52 ( $= 5.52\text{MW} \times \$1/\text{MWh}$ ). The economic benefit to each of the entities can be summarized in Table II.

TABLE II  
ECONOMIC IMPACT OF SHIFTING REACTIVE POWER TO REAL POWER,  $B_2$ .

Participant	Economic Impact ( $B_2$ )	Impact Type
LSE	$B_{2,LSE} = (C_{LCU} - C_{GCU} - T) \cdot \Delta P_{shift}$	Reduced Payment
GCU	$B_{2,GCU} = C_{GCU} \cdot \Delta P_{shift}$	Increased revenue
LCU	$B_{2,LCU} = -C_{LCU} \cdot \Delta P_{shift}$	Reduced revenue
TO	$B_{2,TO} = T \cdot \Delta P_{shift}$	Increased revenue
Production Cost	$B_{2,PC} = (C_{LCU} - C_{GCU}) \cdot \Delta P_{shift}$	Reduced total production cost

where:

- $B_2$  = the benefit from shifting reactive power flow to real power flow without considering change of transfer capability;
- $C_{LCU}$  = the cost of the expensive Load Center Unit;
- $\Delta P_{shift}$  = the increase in real power flow from GCU due to the shift of reactive power flow to real power flow.

### II.3. Benefit from Increased Maximum Transfer Capability ( $B_3$ )

In the previous analysis, the maximum transfer capability is assumed to be unchanged. However, it is very possible that the transfer capability is limited by the voltage stability. If this is the case, the local reactive power (Var) compensation in the stressed area may increase the maximum transfer capability constrained by voltage stability. This is shown in the PV (or SV) curve of Fig. 2. It should be noted that a typical 25% security margin (SM) may be necessary to provide a comfortable margin for keeping the system from a voltage collapse. There are various ways to calculate the change of transfer capability with respect to a change of system conditions [10]-[11] including local Var injection. We have chosen to calculate it using the equation of the maximum real power transfer in a two-bus model [12] as follows:

$$P_{max} = \frac{E^2 \left( -k + \sqrt{1+k^2} \right)}{2X}, \text{ where } k = \frac{Q}{P} \quad (4)$$

Again, assume the compensation lifts the power factor at the load center from 0.9 to 0.95, i.e., from 90 MW+j43.59 MVar to 90 MW + j29.58 MVar. Also assume that the GCU voltage remains at  $1.0 \angle 0^\circ$ . It can be easily verified that the maximum transfer capacity has been improved by 15.5%. Therefore, the load center may receive 103.95 MW ( $=90 \times 1.155$ ) of lower-cost power from the generation center while the same stability margin is maintained. That is, the load center may receive another 8.43 MW ( $=103.95-95.52$ ) due to the increase of the transfer capability. Ignoring the extra line loss caused by this transfer capability increase, the lower-cost generation dispatch is increased by 8.43 MW while the higher-cost local generator dispatch is decreased by 8.43 MW.

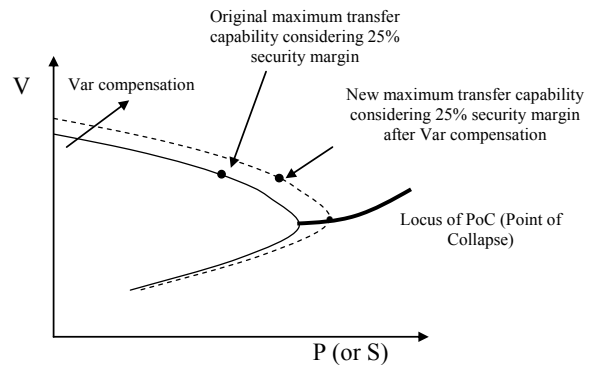


Fig. 2. The original and new transfer capability considering 25% security margin

Similar to the second category, the production cost will be increased by \$42.17 ( $=8.43 \times (25-20)$ ). The LSE payment will be reduced by \$33.72 ( $=42.15-8.43$ ) due to the increased transfer through the tie-line, minus the additional payment to the TO. The GCU will receive increased revenue of \$168.60 ( $=8.43 \times 20$ ) and LCU will have reduced revenue of \$210.75 ( $=8.43 \times 25$ ). In addition, the TO will receive more transmission tariff of \$8.43 ( $=8.43 \times 1$ ) due to more flow through the tie-line.

The above discussion can be summarized in Table III below.

TABLE III  
ECONOMIC IMPACT OF INCREASING MAXIMUM TRANSFER CAPABILITY,  $B_3$

Participant	Economic Impact ( $B_3$ )	Impact Type
LSE	$B_{3,LSE} = (C_{LCU} - C_{GCU} - T) \cdot \Delta P_{TL}$	Reduced payment
GCU	$B_{3,GCU} = C_{GCU} \cdot \Delta P_{TL}$	Increased revenue
LCU	$B_{3,LCU} = -C_{LCU} \cdot \Delta P_{TL}$	Reduced revenue
TO	$B_{3,TO} = T \cdot \Delta P_{TL}$	Increased tariff revenue
Production Cost	$B_{3,PC} = (C_{LCU} - C_{GCU}) \cdot \Delta P_{TL}$	Reduced total production cost

where:

- $B_3$  = the economic impact from the increased transfer capability;

$\Delta P_{TL}$  = the tie-line transfer change.

In the above table, the change in the amount of power transfer at the delivery and the receiving ends is considered the same by ignoring the additional loss caused by the additional transfer in the tie line. If the additional loss must be considered, a slight modification may be applied. For instance, the production cost reduction will be given by:

$$B_{3,PC} = C_{LCU} \cdot \Delta P_{TL\_LCU} - C_{GCU} \cdot \Delta P_{TL\_GCU} \quad (5)$$

where  $\Delta P_{TL\_LCU}$  and  $\Delta P_{TL\_GCU}$  are the change of generation output of LCU and GCU. If their difference is ignored (by taking their average), it can be simplified to the equations in Table III.

#### II.4. Summary

As the previous sample shows, the economic benefit from local Var compensation may be classified into three categories, (1) savings due to reduced losses ( $B_1$ ), (2) savings due from producing more real power from shifting reactive power ( $B_2$ ), and (3) savings from increased transmission transfer capability ( $B_3$ ). It should be noted that these three categories may not always be applicable for all scenarios. For example, Table IV shows the applicability of three economic impacts under three typical scenarios. The categorization is helpful in understanding the theoretic analysis of Var compensation benefits. Also, it can be useful for the calculation of the incremental benefits during different phases in an expansion project. For instance, if the tie-line of a load center and a generation center is limited by the Contracted MW,  $B_1$  should be the only part used to calculate the economic benefit of a project to interconnect Var compensators. If there is a phase 2 of the project that relaxes the line flow constraint due to de-regulation or a bi-lateral agreement to reflect the MVA limit caused by thermal limit, voltage limit or contract MVA limit, then  $B_1$  and  $B_2$  would both apply. Further, if the tie-line limit is relaxed in a phase 3 of the expansion project to aggressively consider the voltage stability limit increase due to Var compensation, then the benefits under all categories would apply. Hence, the benefits can be analyzed in an incremental fashion as demonstrated with the two-bus example.

TABLE IV  
APPLICABILITY OF THE THREE ECONOMIC IMPACTS UNDER  
DIFFERENT TIE-LINE FLOW SCENARIOS

Scenarios of tie-line flow	$B_1$	$B_2$	$B_3$
Limited by contracted MW	√		
Limited due to MVA rating	√	√	
Limited due to voltage stability	√	√	√

Despite the different applicability of these three economic impacts under the different scenarios given above, the following discussion will assume the tie-line flow is limited due to voltage stability for illustration

purposes. In fact, an important reason for Var compensation is to improve the stressed voltage stability, therefore, it is reasonable to focus on the case that all three categories are applicable.

In summary, the total economic impact to the LSE can be described as follows:

$$\begin{aligned} B_{T,LSE} &= B_{1,LSE} + B_{2,LSE} + B_{3,LSE} \\ &= (C_{GCU} - T) \cdot \Delta P_{loss} + (C_{LCU} - C_{GCU} - T) \cdot \Delta P_{shift} + \\ &\quad (C_{LCU} - C_{GCU} - T) \cdot \Delta P_{TL} \\ &= (C_{GCU} - T) \cdot \Delta P_{loss} + \\ &\quad (C_{LCU} - C_{GCU} - T) \cdot (\Delta P_{shift} + \Delta P_{TL}) \end{aligned} \quad (6)$$

Similarly, the total economic impacts to the other market participants, GCU, LCU, and TO as well as the total production cost (as an indication of the societal efficiency) can be described as follows:

$$\begin{aligned} B_{T,GCU} &= -C_{GCU} \cdot \Delta P_{loss} + \\ &\quad C_{GCU} \cdot \Delta P_{shift} + C_{GCU} \cdot \Delta P_{TL} \end{aligned} \quad (7)$$

$$B_{T,LCU} = -C_{LCU} \cdot \Delta P_{shift} - C_{LCU} \cdot \Delta P_{TL} \quad (8)$$

$$B_{T,TO} = T \cdot (\Delta P_{loss} + \Delta P_{shift} + \Delta P_{TL}) \quad (9)$$

$$\begin{aligned} B_{T,PC} &= C_{GCU} \cdot \Delta P_{loss} + \\ &\quad (C_{LCU} - C_{GCU}) \cdot (\Delta P_{shift} + \Delta P_{TL}) \end{aligned} \quad (10)$$

where:

$B_T = B_1 + B_2 + B_3$  and is the total economic impact;

$B_{T,PC}$  = the economic impact for the total production cost.

As seen from the above equations, to evaluate the economic impact to different market players, it is critical to properly evaluate  $\Delta P_{loss}$ ,  $\Delta P_{shift}$ , and  $\Delta P_{TL}$ . If there is no tariff, the benefit to the LSE is the same as the total system production cost benefit. The next section will give an approach to quickly evaluate the three components in a more complicated, practical power system.

### III. Quantitative Evaluation of Reactive Power Benefits

This section presents a generic formulation for more practical power networks to assess the economic benefits of Var compensation via comparisons of three different cases of market-based optimal generation dispatch. The dispatch is performed for the three cases using Optimal Power Flow (OPF) [13] with respect to transmission limits and inter-tie transfer capability limits. The three cases are as follows:

- (1) *Base Case: Base system without Var compensation ( $Q_c=0$ );*
- (2) *Case 1: Compensation is available at a given bus in a given amount and the original interface transfer limit is maintained;*
- (3) *Case 2: Compensation is available as in Case 1 and a new interface transfer limit is applied.*

The objective of the OPF for the above three cases is to minimize the production cost. The constraints include the limits of the transmission network. The dispatch formulation in the OPF model can be written as follows:

$$\text{Min: } \sum f(P_{Gi}) \text{ (Generation production cost)} \quad (11)$$

Subject to:

$$P_{Gi} - P_{Li} - P(V, \theta) = 0 \text{ (Real power balance)} \quad (12)$$

$$\begin{aligned} Q_{Gi} + Q_{Ci} + \\ -Q_{Li} - Q(V, \theta) = 0 \end{aligned} \text{ (Reactive power balance)} \quad (13)$$

$$|LF_k| \leq LF_k^{\max} \text{ (Line flow limits)} \quad (14)$$

$$IT_k^{\min} \leq IT_k \leq IT_k^{\max} \quad (15)$$

(Inter-tie flow or transfer capability limits)

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max} \text{ (Generation real power limits)} \quad (16)$$

$$Q_{Gi}^{\min} \leq Q_{Gi} \leq Q_{Gi}^{\max} \text{ (Generation reactive power limits)} \quad (17)$$

$$V_i^{\min} \leq V_i \leq V_i^{\max} \text{ (Voltage limits)} \quad (18)$$

$$Q_{ci}^{\min} \leq Q_{ci} \leq Q_{ci}^{\max} \text{ (Compensation limits)} \quad (19)$$

More detailed models for OPF may be applied such as limits for transformer tap settings, range of phase shifters, amount of interruptible load, etc. However, since the topic of this paper is to present a methodology to calculate the benefit of local Var compensation, those details are ignored for simplicity and to focus on the quantitative evaluation formulation.

After the optimal dispatches are performed for the three cases above, the benefits  $B_1$ ,  $B_2$  and  $B_3$  may be identified using the following approach.

1. Perform OPF runs for the Base Case and Case 1.
2. Calculate the total loss reduction from Base Case to Case 1. This MW amount is  $\Delta P_{loss}$ . Then,  $\Delta P_{shift}$  is the sum of  $\Delta P_{loss}$  and the net increased MW generation at GCU.
3. Perform OPF for Case 2.
4. Calculate the changes of MW dispatch in the GCU and the LCU from Case 1 to Case 2.
5. Obtain the marginal cost in GCU and LCU from the Base Case. These values are  $C_{GCU}$  and  $C_{LCU}$ , respectively.
6. Apply Eqs. (1-5) to calculate the three economic benefits,  $B_1$ ,  $B_2$ , and  $B_3$ , and totals for the various market participants.

7. Obtain the production cost difference between the Base Case and Case 2. This is the total accurate economic benefit,  $B_T$ .
8. Usually,  $B_T$  is not exactly equal to  $B_1+B_2+B_3$  due to non-linearity of the system, however,  $B_1$ ,  $B_2$ , and  $B_3$  can be adjusted proportionally such that  $B_1+B_2+B_3 = B_T$ .
9. Steps 1-9 need to be repeated if many different operating hours or scenarios are considered.

As shown in Step 8, the total economic benefit,  $B_T$  is the production cost difference between the Base Case and Case 2. However, the power system is essentially non-linear and the factors of power losses, shifting reactive power flow to real power flow, and the maximum transfer capability are not fully independent and can affect one another's outcome. All of these make  $B_T$  likely to be different from  $B_1+B_2+B_3$ , calculated from Step 6. Therefore, it is reasonable in Step 8 to use a simple proportioning to adjust  $B_1$ ,  $B_2$ , and  $B_3$  to equal  $B_T$ . Since the amount of Var compensation is relatively small, the difference and adjustment should be reasonably small as well. Certainly, if there is no need to separate the three benefits, only the Base Case and Case 2 simulations need to be run.

## IV. Case Study with Results

### IV.1. Test System

In this section the 7-bus test system from PowerWorld [14] is used to demonstrate the economic benefits from Var compensation. The diagram of the test system is shown in Fig. 3. The data for the loads, generation, transmission thermal limits and voltage limits are shown in Table V. In order to study the increased maximum transfer capability for the tie lines, the test system was divided into two areas, the Load Center (LC) in the top and the Generation Center (GC) in the bottom, as shown in Fig. 3 and detailed in Table VI. The generators in the LC are more expensive than those in the GC.

The interface tie lines between the two areas are lines 6-2 and 7-5. The voltage stability limit (the nose point of the P(S)-V curve) is 464 MVA, which is lower than the sum of the two lines' thermal limits (500 MVA). If the voltage stability margin is assumed to be 25%, then the interface transfer limit is 348 MVA (=464×75%).

In this test, it is assumed that a 15 MVar compensator will be installed at Bus 3, where the lowest voltage occurs as indicated by the power flow study of the base case. Although the location and amount of Var installation should follow a more rigorous approach considering engineering and economic tradeoffs, in this case Bus 3 is chosen simply for illustrative purposes. The 15 MVar compensation at Bus 3 raises the voltage stability limit by 28MVA to 492 MVA. Considering a 25% margin, the new interface transfer limit is raised by 21 MVA to 369 MVA (=492×75%).

The OPF models for the three cases are solved by the Nonlinear Programming (NLP) solver MINOS, a

software package for solving large-scale linear and nonlinear optimization.

The study below focuses on the benefit to LSE. Thus, the subscript LSE in the benefit calculation is omitted for notational convenience. The benefits to other participants can be obtained similarly.

Here it is assumed that there is no transmission tariff, therefore, the benefit to the LSE is equal to the production cost reduction.

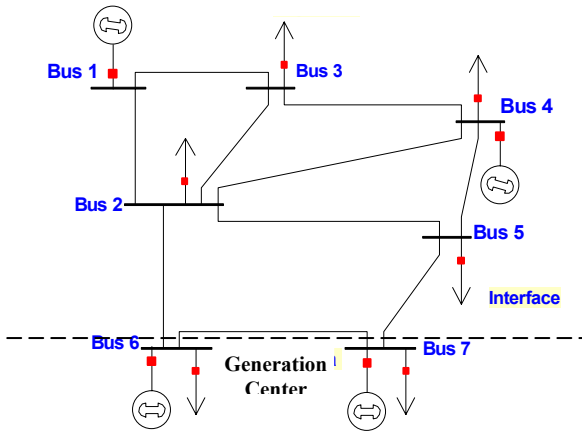


Fig. 3. Diagram of a 7-bus test system

TABLE V  
PARAMETERS OF THE TEST SYSTEM

Power base: 100MVA Voltage base: 138kV										
Load										
Bus	1	2	3	4	5	6	7			
$P_L$ (MW)	0	100	190	150	200	50	80			
$Q_L$ (MVar)	0	40	75	50	60	20	40			
Generator fuel cost										
Bus	1	4	6	7						
$a$ (\$/h)	798.92	814.03	515.34	400.41						
$b$ (\$/MWh)	20	19	14	15						
Marginal cost (\$/MWh)	20	19	14	15						
Active power generation limits (MW)										
Bus	1	4	6	7						
$P_G^{\max}$	150	200	300	300						
$P_G^{\min}$	70	50	60	0						
Reactive power generation limits (MVar)										
Bus	1	4	6	7						
$Q_G^{\max}$	100	100	100	100						
$Q_G^{\min}$	-100	-100	-100	-100						
Transmission line thermal limits (MVA)										
Line	1-2	1-3	2-3	2-4	2-5	4-3	5-4	6-2	6-7	7-5
Limit	120	100	100	100	100	120	80	250	100	250
Voltage limits (p.u.)										
$V_{\max} = 1.05$ to $V_{\min} = 0.95$ for every bus.										

TABLE VI  
LOAD AND GENERATION IN TWO AREAS

Area	Bus	Gen. Cap. (MW)	Load (MW)	Margin (MW)
Load Center	1, 2, 3, 4, 5	350	640	-290
Gen. Center	6, 7	600	130	470

TABLE VII  
BASE CASE RESULTS

System: No Var source, tie lines limit is 348 MVA				
Total fuel cost : 15283.28\$/hr				
Real power loss: 11.302MW				
Active power generation (MW)				
Bus	1	4	6	7
$P_G$	107.010	200.000	300.000	174.292
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	188.691	159.309	348	

TABLE VIII  
CASE 1 RESULTS

System: 15 MVar source at Bus 3, tie lines limit is 348 MVA				
Total fuel cost : 15273.04 \$/hr				
Real power loss: 10.927MW				
Active power generation (MW)				
Bus	1	4	6	7
$P_G$	106.087	200.000	300.000	174.839
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	188.820	159.180	348	

TABLE IX  
CASE 2 RESULTS

System: 15 MVar source at Bus 3, tie lines limit is 369 MVA				
Total fuel cost : 15169.13 \$/hr				
Real power loss: 10.939MW				
Active power generation (MW)				
Bus	1	4	6	7
$P_G$	85.267	200.000	300.000	195.672
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	198	171	369	

## IV.2. Results

From Tables VII and VIII, it is shown that the total amount of dispatch has been reduced by 0.376 MW (=780.926-781.302) in Case 1 from the Base Case. So,  $\Delta P_{loss}$  is 0.376 MW. Also, the total dispatch of the GC is increased by 0.547 MW (=474.839-474.292). With the assumption that the reduced loss is due to the dispatch reduction at the GC, this implies that 0.923 MW (=0.376 + 0.547) additional real power is dispatched from the GC because of the shift of reactive power flow to real power flow. Hence, we have  $\Delta P_{shift} = 0.923$  MW. It should be noted that the 0.923 MW  $\Delta P_{shift}$  is also very close to the reduced generation at the LC, 0.923 MW. This implies that the extra loss caused by  $\Delta P_{shift}$  is negligible. This verifies that it is technically justifiable to decouple  $\Delta P_{loss}$  and  $\Delta P_{shift}$ .

Table IX shows the test results from Case 2, in which the transfer capability is increased from 348 MVA to 369 MVA. The table shows that the GC units deliver 20.833 MW (=495.672-474.839) more in Case 2 than in Case 1, and the LC units in Case 2 generate 20.820 MW (=306.087-285.267) less than in Case 1. The slight difference, 0.013 MW, is due to the power loss because of the additional MW transfer capability. The additional



import of 20.820 MW is very close to the increased transfer capability, 21 MVA (369-348). This means that almost all increased MVA capacity is used to deliver cheaper real power to the LC. This is very reasonable.

In this test, the cost of the marginal units at Bus 7 and 1 will be employed as  $C_{GCU}$  and  $C_{LCU}$  for the marginal cost of the GC and the LC, respectively. Hence, considering fuel cost is given as  $(a + bP_{Gi})$ , we have  $C_{GCU} = \$15/\text{MWh}$  and  $C_{LCU} = \$20/\text{MWh}$ . Using equations given in Tables I-III, we can obtain the benefits as follows:

$$\begin{aligned} B_1 &= 15 \times 0.375 = \$5.63/\text{hr} \\ B_2 &= (20-15) \times 0.922 = \$4.61/\text{hr} \\ B_3 &= 20 \times 20.820 - 15 \times 20.833 = \$103.91/\text{hr} \\ B_1 + B_2 + B_3 &= \$114.15/\text{hr} \end{aligned}$$

In the above calculation,  $B_3$  is calculated using  $B_3 = C_{LCU} \cdot \Delta P_{TL\_LCU} - C_{GCU} \cdot \Delta P_{TL\_GCU}$ , as discussed in Section II.3. In this test, the actual total benefit  $B_T$  to the LSE is equal to  $\$114.15/\text{hr}$  ( $=15283.28 - 15169.13$ ), which is the reduced production cost from the Base Case to Case 2. Hence, in this case there is no need to adjust  $B_1$ ,  $B_2$ , and  $B_3$ . However, as it was mentioned earlier in some other cases,  $B_T$  to LSE may not be the same as  $B_1 + B_2 + B_3$ , numerically, due to the non-linearity of the system.

The above simulation was a one-hour test. If multiple hours or scenarios need to be simulated, we may simply employ a chronological simulation or some estimation from several typical hours as discussed in Section II. It can be easily verified that the total benefit to the LSE as well as the system production cost in  $\$/\text{MVar}\cdot\text{year}$  is significant compared to the Var payment to central generators or power factor penalties.

### V. Sensitivity Analysis

The previous section analyzes a case study for different categories of reactive power (Var) benefits. This section will expand the discussion to address the benefit study with respect to different Var compensation amounts and locations. Here it is assumed that Bus 2, Bus 3, and Bus 5 are three Var compensation location candidates. By applying the approach in section IV with the different Var compensation, Figs. 4-6 provide the trend of economic benefits versus Var compensation at Bus 2, Bus 3, and Bus 5, respectively. It should be noted that the Transmission Transfer Capability (TTC) OPF model [15] becomes infeasible if  $Q_c$  is greater than 200MVar at any bus, so the upper limit of  $Q_c$  size in this case is set to 200MVar.

There are some commonalities found in Figs. 4-6. The shape of  $B_T$ , from reduced losses vs. Var compensation is similar to a hill. The uphill part is due to the reduction of current flow from the injection of reactive power at the LC, therefore the lower losses

raise the  $B_T$  benefit. The reason for the downhill part is the over-injected reactive power that can not be consumed by the loads and has to be balanced by generators. Therefore, the overprovided (beyond what the local bus load can consume) reactive power has to be transferred through the lines. As a result, the line current increases, and the  $I^2R$  losses increase.

The  $B_2$  benefit, from shifting reactive power flow to real power flow, vs. Var compensation increases slowly and may have a somewhat saturated feature when  $Q_c$  reaches a certain level indicating a diminishing return with greater amounts of Var compensation as shown in Figs. 4-6. In fact, it drops off in Fig. 6 after reaching a VAR threshold.

The shape of the  $B_3$  benefit, from increased tie line transfer limit, versus Var compensation is roughly proportional to the TTC change versus Var compensation, because the increased tie line transfer capability leads to increased cheap power dispatch from the GC to the LC. An interesting observation is that  $B_3$  slowly drops off after reaching its maximum value, and then slowly increases again. Usually,  $B_3$  and TTC are considered to increase with more Var compensation, but it is only true in a specific range. In fact, it may decrease with more Var compensation when  $Q_c$  is greater than a threshold. This trend affects both  $B_3$  and the total benefit  $B_T$  greatly. It should be noted that the occasional step changes in Figs. 4-6 because some limits become binding.

The total benefit  $B_T$  is generally the most important benefit indicator or index to decision-makers. The total benefit from Var compensation at Buses 2, 3 and 5 are shown in Fig. 7 for convenient comparison. It is clearly shown that economically it may not be wise to put too much Var compensation on the system since there is a point of diminishing return after which the total benefit drops off. Thus, it is important to give careful consideration to the amount and location of Var compensation to maximize its benefits.

Also, this study has assumed that the Var compensation is variable between its maximum and minimum Var ranges which are not the case in general practice. Instead, the Var compensators will have fixed steps that can make the analysis easier with less simulation runs to conduct.

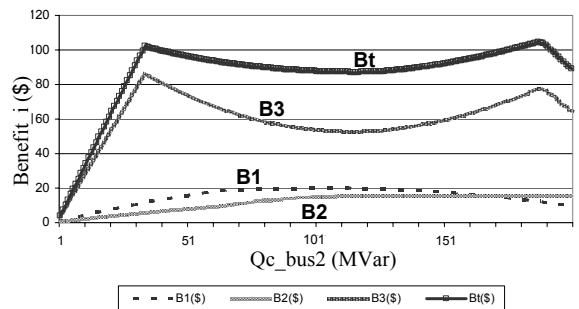


Fig. 4.  $B_1$ ,  $B_2$ ,  $B_3$ , and  $B_T$  versus Var compensation at Bus 2

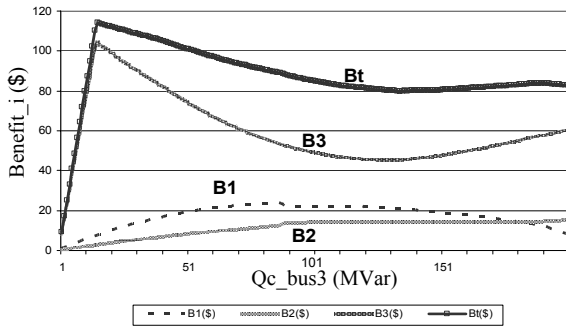


Fig. 5.  $B_1$ ,  $B_2$ ,  $B_3$ , and  $B_t$  versus Var compensation at Bus 3

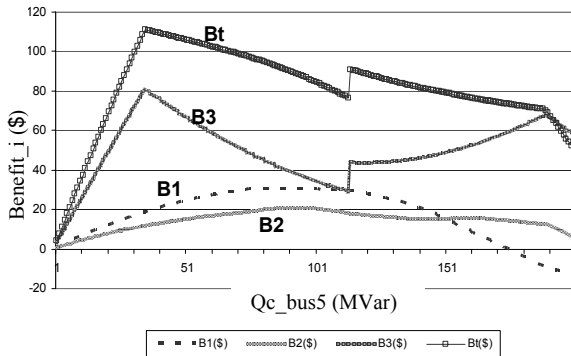


Fig. 6.  $B_1$ ,  $B_2$ ,  $B_3$ , and  $B_t$  versus Var compensation at Bus 5

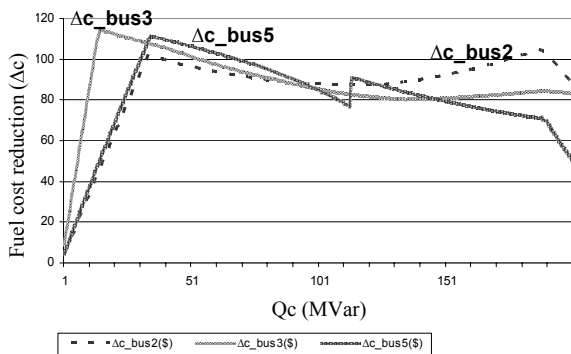


Fig. 7. Total benefit  $B_t$  at candidate buses versus Var compensation

## VI. Conclusions

The conclusions and need for future work based on this research are summarized as follows:

- A systematic approach has been presented for analyzing the economic benefits from local Var compensation to various market parties in electricity supply, delivery and consumption. The economic benefit may be classified into three categories: (1) loss reduction, (2) shift reactive power to real power flow, and (3) increase maximum transfer capability. Under different operational scenarios, a different set of the three categories of economic benefits may apply. The classification may be used in the future to give a fast evaluation of economic benefit from Var compensation. Also, it may be helpful in the design of future Var markets and pricing for

different components and parties. In addition, the different economic impact for the different participants may be used as a criterion to share the benefits and costs (installation and maintenance) among the different participants for a Var compensator project.

- The results of the sample two-bus system and more realistic seven-bus system indicate that the economic benefit from local Var compensation can be significant if compared with the payment to central generators or power factor penalties. This implies that it will be necessary to include the growing reactive power producing DERs and other local Var sources into future reactive power producing (Var) markets.
- The results of the sensitivity of Var benefits with respect to the amount of Var compensation indicates that the economic efficiency may not continue to grow as the Var compensation increases. In fact, the benefits may decrease at some point as the Var compensation increases. Thus, it is important to give careful consideration to the amount and location of Var compensation. Also, it will be important to determine the threshold for diminishing Var returns to reduce unneeded Var investments and maximize total benefits.
- The paper assumes devices that have a Var compensation that stays constant and does not vary with the voltage (constant Var injection). In the future, an in-depth analysis of different Var sources is needed because they may have different power-to-voltage characteristics, such as capacitor banks which have reactive power that increases or decreases with the square of the voltage, as well as operating limitations, such as variable Vars vs. step changes.
- Finally, the study has not considered the benefits that Var compensators with faster dynamics bring. With faster responding Var compensators, additional benefits such as increasing the margin-to-voltage collapse can become another important benefit. This is an area of future research.

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