

Assessment of the Economic Benefits from Reactive Power Compensation

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Abstract—The U.S. power industry is under great pressure to provide reactive power or Var support. Although it is generally known that there are technical benefits for utilities and industrial customers to provide local reactive power support, a thorough quantitative investigation of the economic benefit is greatly needed. This paper seeks to provide a quantitative approach to evaluate the benefits from local reactive power compensation. This paper investigates the benefits including reduced losses, shifting reactive power flow to real power flow, and increased transfer capability. These benefits are illustrated with a simple two-bus model and then presented with a more complicated model using Optimal Power Flow. Tests are conducted on a system with seven buses in two areas. These simulations show that the economic benefits can be significant, if compared with capacity payment to central generators or power factor penalties applied to utilities. This economic value may give utilities a better understanding of the Var benefits to assist their cost-benefit analysis for Var compensation. In addition, since the economic benefits are significant, this paper suggests that the future reactive power market should consider local Var providers.

Index Terms—Economic evaluation, reactive power compensation, transfer capability, optimal power flow.

I. INTRODUCTION

THE US power industry has been under great pressure to serve load economically since deregulation was 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. Several study initiatives have been set up among utilities, independent system operators (ISOs), and the government to address the reactive power issue. FERC has commissioned a study to evaluate the reactive power market both in the U.S. and internationally [1]. The Department of Energy has sponsored the Oak Ridge National Laboratory to investigate the economic benefits of local reactive power compensation, which is generally considered efficient since reactive power does not travel well over long transmission lines [2]. Especially, due to the increasing need

for power quality and transient stability, dynamic Var compensators have received much interest. These dynamic compensators include pure Var compensators like synchronous condensers, Static Var Compensators (SVCs), STATCOMs, as well as distributed energy resources (DERs) like fuel cells and microturbines that can also provide local Var support. Several previous works have discussed the cost [2] and the technical benefits [3-6] of dynamic reactive power compensation. However, the cost of local dynamic Var sources is unfortunately high and there is a lack of a standard method to evaluate the economic benefits. These issues along with an undeveloped reactive power market make it difficult to economically justify the installation of a dynamic Var source. To address this issue, this paper demonstrates a possible quantitative approach to assess the “hidden” benefits from Var sources at the demand side. The results from this research show some significant economic benefits to load-serving utilities, which may increase their interests in local Var installation and influence their decision-making process.

Estimating the benefits of the local Var compensation can be quite complicated. 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 Var means less Var capacity from central generators. Various ISOs in the US provide payment in the range of \$1,000~\$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 to customers. The data among nationwide utilities shows that the typical penalty is about \$0.10/kW-month [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 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 quantitative approach. Certainly, it is not possible to include all benefits in the form of dollars. However, the method developed in this paper does present a systematic approach to quantify some important benefits from

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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 operators. This means that the dispatch may change with the connection and operation of local Vars. It should be noted that the discussion in this paper is from the viewpoint of the load-serving utility. That is, all benefits are with the load. Certainly, other entities may have reduced or increased revenues, compared to the case without compensation. Therefore, the allocation of the installation cost and operation benefit of Var compensators needs more investigation in the future.

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 Var compensation and Section V presents the conclusion.

II. BENEFITS FROM A VAR SOURCE IN A TWO-BUS SYSTEM

Several economic benefits will be discussed and categorized in this section. To help readers understand these benefits, a two-bus system shown in Fig. 1 is used to illustrate the systematic methodology for capturing the hidden benefits.

In Fig. 1, there is a generation bus, a load bus, and a line connecting the two buses. The generation bus represents a generation center, the load bus represents a load center, and the line represents an inter-tie or an interface between the two areas. The tie line is subject to the maximum transfer capability between two areas.

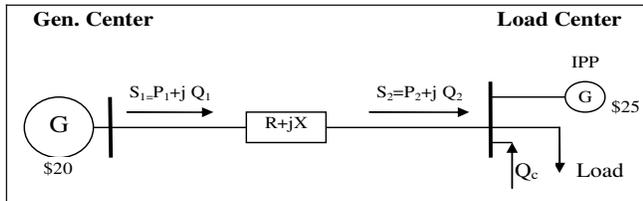


Fig. 1. A two-bus system

The generation center has a cheap unit with a cost of \$20/MWh. The load center has a large amount of load, served by a utility as a load-serving entity, and an expensive unit, owned by an Independent Power Producer (IPP), with a cost of \$25/MWh. The net load of the load center (i.e., the total load minus the total local generation) is 100 MVA 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 generation center through the tie line. The other parameters are as follows: the power base is 100 MVA; the voltage at the generation center 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 load center is stressed and the tie-line

is congested at its maximum transfer capability of 100 MVA at the receiving end, constrained by voltage stability. Also, the assumption is that the local compensation device will constantly inject $Q_c=14.01$ MVar to lift the load power factor to 0.95, i.e., $P'_2=P_2=90$ MW and $Q'_2=Q_2-Q_c=43.59-14.01=29.58$ MVar.

The economic benefits from local Var compensation are classified into three categories. Each of these is discussed below. Also, hard-to-quantify benefits are mentioned.

A. Benefit from Reduced Losses (B_1)

Injection of reactive power at the receiving end reduces the reactive power through the tie line and therefore reduces the line current. Since the real power loss is I^2R , the loss will be reduced if the current is reduced. With the consideration of the load-side voltage magnitude remains unchanged and very close to 1.0, the original line loss and the power at the delivery end before the Q_c compensation are given as follows.

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

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

After Q_c is connected, the power losses and delivery end power are as follows.

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

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

Therefore, the total loss savings at the delivery end is 0.2 MW (92-91.8) or 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 because the loss reduction may be stretched to almost every hour of the 8760 hours per year. So, the annual saving will be \$35,040/year ($20 \cdot 0.2 \cdot 8760$) if the same amount of load is assumed for every hour. Therefore, the savings in dollars per MVar-year is \$2,501/MVar-year ($35,040/14.01$).

The actual loss savings at every hour varies because the actual load varies at different hours. The total amount of this benefit can be calculated as the sum of savings of each hour after an hour-by-hour, chronological simulation of 8760 hours. Practically, the time-consuming chronological simulation may be replaced with some assumption and estimation using either (1) the average hour scenario or (2) several typical scenarios like peak and valley loads and their corresponding durations. For a very simple example, if this congested case does not occur in all 8760 hours and the average tie line flow is assumed to be only 70% of the congested flow, it can be verified that the reduced loss is about 64% of the whole-year congested case. This is still quite considerable compared with the reactive power payment or penalty mentioned in Section I.

Under this category, the load will pay less due to the line loss reduction, while the unit at generation center will have reduced revenue after the Var compensator is connected.

B. Benefit from Shifting Reactive Power Flow to Real Power Flow (B_2)

As previously assumed, the tie line is congested due to the maximum transfer capability of 100 MVA at the receiving end. In some cases, this limit may not be increased due to other limiting factors like thermal rating. However, it is more likely that the maximum transfer limit may increase after the local Var compensation. If this is the case, it is still assumed that the limit of S_2 remains at 100 MVA. The reason is that the possibly increased amount of transfer capability affects the tie-line tariff collected by the transmission owner, as discussed in the next sub-section. Therefore, it is temporarily assumed no change of transfer capability.

Since the reactive power flow, Q_2 , has been reduced due to local compensation, this makes it possible to have more real power delivered from the lower-cost generator while the 100 MVA limit is still respected because of $P_2 = \sqrt{S_2^2 - Q_2^2}$. This benefit of transferring more cheap real power while keeping the same transfer capability is classified as the benefit of shifting reactive power flow to real power flow, as in the title of this subsection.

With the same case in Fig. 1, after the compensation, Q_2 has been reduced to 29.58 MVar to give a 0.95 lagging power factor for the net load at the load center. The new real power transferred over the tie-line is given as

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

Hence, the additional deliverable real power is 5.52 MW. Ignoring the additional loss due to the 5.52 MW, this is the amount of additional lower-cost real power from the generation center to the load center. Therefore, if a re-dispatch is performed, the local higher-cost generation will be reduced by 5.52 MW. The economic benefit to the load-serving utility will be the reduced production cost equal to the 5.52 MW times the price difference between the two generators.

When a full year is considered, an hour-by-hour accumulation is needed for hours when the maximum transfer capability is reached and limits additional power transfer. Assuming the tie line is congested during 2 peak months, the total savings due to the shifting of reactive power flow to real power flow is equal to \$39744/year [(25-20)*5.52*60*24]. Hence, the savings per MVar-year for the load center is \$2,837/MVar-year.

Under this category, the load will pay less due to the shift of reactive power flow to real power flow. Meanwhile, the unit at the generation center will receive increased revenue due to increased MW dispatch. Similarly, the IPP unit at the load center will receive reduced revenue due to reduced dispatch.

C. 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

local Var compensation in the stressed area may increase the maximum transfer capability constrained by voltage stability. This is shown in Fig. 2.

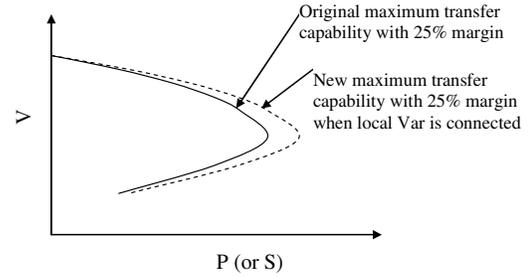


Fig. 2. The original and new transfer capability considering security margin.

There are various ways to calculate the change of transfer capability with respect to a change of system conditions [7-8] including local Var injection. Here the equation of the maximum real power transfer in a two-bus model [9] is employed as follows:

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

Again, assume the compensation lifts the power factor from 0.9 to 0.95, i.e., from 90 MW+j43.59 MVar to 90 MW + j29.58 MVar. Also assume the generation center 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 (90×1.155) 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 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. With the previously assumed 2 months of peak load, the saved production cost due to the increased transfer capability is equal to \$61,416/year [(25-20)*8.53*60*24]. Hence, the benefit in \$/MVar-year is \$4384 /MVar-year ($61416/14.01$).

Similar to the second category, the load will pay less under this consideration due to the increased transfer through the tie-line. Also, the unit at the generation center will receive increased revenue and the IPP unit at the load center will receive reduced revenue. In addition, the transmission company may receive more transmission tariff due to more MVA flow through the tie-line. This is also an important reason to distinguish this benefit from the previous one.

D. Summary

As the previous sample shows, the benefits of local Var compensation to load-serving utilities may be as significant as thousands of dollars per MVar-year. This is due to the more efficient generation re-dispatches. Therefore, the load-serving utilities may pay less to purchase electricity. It should be noted that from the viewpoint of other participants like the unit at the generation center, the IPP unit, and the transmission company, they may have increased or reduced revenue as discussed at

the end of each previous three sub-sections.

Given the sample system above, it is straightforward to conclude the following equations:

$$B_T = B_1 + B_2 + B_3 \quad (1)$$

$$B_1 = \sum_{\text{all hours}} C_G \cdot \Delta P_{\text{loss}} \quad (2)$$

$$B_2 = \sum_{\text{congested hours}} (C_L - C_G) \cdot \Delta P_{\text{shift}} \quad (3)$$

$$B_3 = \sum_{\text{congested hours}} (C_L \cdot \Delta P_{\text{inc_trans_L}} - C_G \cdot \Delta P_{\text{inc_trans_G}}) \quad (4)$$

where

- B_T = the total benefit from local Var compensation;
- B_1 = the benefit from reduced loss;
- B_2 = the benefit from shifting reactive power flow to real power flow without considering change of transfer capability;
- B_3 = the benefit from the increased transfer capability;
- C_G = the average cost of the generators at the generation center;
- C_L = the average cost of the generators at the load center;
- ΔP_{loss} = the reduced loss;
- ΔP_{shift} = the shift of reactive power flow to real power flow;
- $\Delta P_{\text{inc_trans_L}}$ = the transfer change at the receiving end;
- $\Delta P_{\text{inc_trans_G}}$ = the transfer change at the delivery end.

In (4), the change of transfer at the delivery end and the receiving end are considered different due to the additional loss caused by the additional transfer in the tie-line. If the additional loss is ignored as in the previous subsection, $\Delta P_{\text{inc_trans_L}}$ should be the same as $\Delta P_{\text{inc_trans_G}}$.

It should be noted that while B_1 is applied to all hours, B_2 and B_3 are applied only to the hours when congestion due to transfer capability occurs. In the hours when transfer capability is not reached, it is not likely to get more real power imported through the tie line after compensation. Otherwise, the base case should have more real power import capability. Other constraints such as generation output limits or other transmission limits may restrict more real power transfer.

There are many other benefits which are difficult to quantify such as improvements in voltage regulation and voltage quality due to local Var compensation. More detailed investigation is needed to address all these benefits more fully.

III. QUANTITATIVE EVALUATION OF REACTIVE POWER BENEFIT

This section presents a generic formulation 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) with respect to transmission limits and inter-tie transfer capability limits [10]. The three cases are as follows:

- Base Case: Base system without Var compensation ($Q_c=0$);*
- Case 1: Compensation is available at a given bus in a given amount and the original interface transfer limit is maintained;*
- 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 networks. The dispatch formulation in the OPF model can be written as follows:

$$\text{Min: } \sum f(P_{Gi}) \quad (5)$$

Subject to:

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

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

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

$$IT_k^{\text{min}} \leq IT_k \leq IT_k^{\text{max}} \quad (\text{Inter-tie flow or transfer capability limits})$$

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

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

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

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

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, the benefits B_1 , B_2 and B_3 may be identified using the following approach.

1. Perform OPF for the Base Case and Case 1.
2. Calculate the total reduced MW generation from Base Case to Case 1. This MW amount is $\Delta P_{\text{loss}} + \Delta P_{\text{shift}}$.
3. Find the reduced system losses, ΔP_{loss} . Then, ΔP_{shift} can be easily obtained.
4. Perform OPF for Case 2.
5. Calculate the changes of MW dispatch in the generation center and the load center from Case 1 to Case 2. These changes are $\Delta P_{\text{inc_trans_G}}$ and $\Delta P_{\text{inc_trans_L}}$.
6. Obtain the average marginal costs in generation center and load center from the Base Case. These values are C_G and C_L , respectively.
7. Apply Eqs. (2-4) to calculate the three economic benefits, B_1 , B_2 , and B_3 .
8. Obtain the production cost difference between the Base Case and Case 2. This is the total accurate economic benefit, B_T .
9. Because B_T is not usually equal to $B_1+B_2+B_3$ due to non-linearity of the system, B_1 , B_2 , and B_3 may be adjusted proportionally such that $B_1+B_2+B_3 = B_T$.
10. Steps 1-9 need to be repeated if many different 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 7. Therefore, it is proposed in Step 9 to use a simple proportion to adjust B_1 , B_2 , and B_3 . 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 simulation needs to be run. The production cost difference is the total benefit.

IV. CASE STUDY WITH RESULTS

A. Test System

In this section the 7-bus test system from PowerWorld [11] 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 1. In order to study the increased maximum transfer capability for the tie lines, the test system is divided into two areas, the Top Area and the Bottom Area, as shown in Fig. 3 and Table 2. The Top Area is a load center, and the Bottom Area is a generation center. The generators in the load center are owned by IPPs and more expensive than those in the generation center.

The interface tie lines between the two areas are line 6-2 and line 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 their thermal limits (500 MVA). If the voltage stability margin is assumed to be 25%, then the interface transfer limit is $464 * 75\% = 348$ MVA.

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 tradeoff, in this case it is chosen simply for illustrative purposes. The 15 MVar compensation at Bus 3 raises the voltage stability limit to 492 MVA. Considering a 25% margin, the new interface limit is set as $492 * 75\% = 369$ MVA.

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

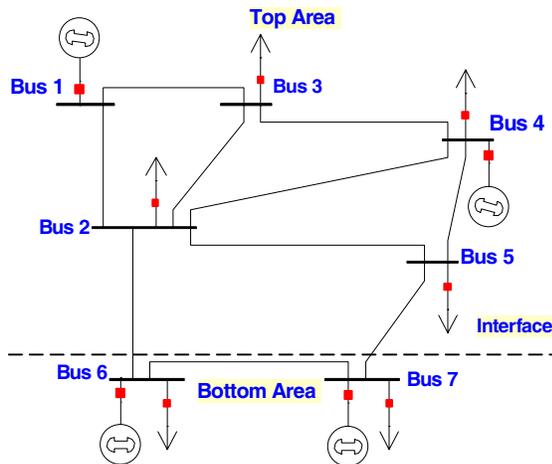


Fig. 3. Diagram of a 7-bus test system.

B. Results

From Tables 3 and 4, it is shown that the total amount of dispatch has been reduced by 0.186 MW in Case 1 from the Base Case. The dispatch of the generation center is increased by 1.698 MW. With the assumption that the reduced loss is due to the dispatch reduction at the generation center, this implies that 1.884 MW ($1.698 + 0.186$) additional real power is dispatched from the generation center because of the shift of reactive power flow to real power flow. Hence, we have $\Delta P_{loss} = 0.186$ MW and $\Delta P_{shift} = 1.884$ MW.

Table 5 shows the test results from Case 2, in which the transfer capability is increased from 348 MVA to 369 MVA. Table 5 shows that the generation center delivers 21.089 MW more to the load center in Case 2 than in Case 1, and the load center generates 20.687 MW less than in Case 1. The slight difference, 0.402 MW, is due to the power loss because of the additional MW transfer capability. The additional import of 20.687 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 load center. This is very reasonable.

In this test, the average cost, weighted by generation changes, of the marginal units is employed to calculate the marginal cost of the whole generation (or load) center. Hence, considering fuel cost and fuel consumption ($a + bP_{Gi}$), we have $C_G = \$15.49/\text{MWh}$ and $C_L = \$16.62/\text{MWh}$. Please note the generator at Bus 4 is not considered when calculating C_L because it is at its maximum output and is not a marginal unit. Using Eqs. (2-4), we can obtain the benefits as follows:

$$\begin{aligned} B_1 &= 15.49 * 0.186 = \$2.88/\text{hr} \\ B_2 &= (16.62 - 15.49) * 1.884 = \$2.13/\text{hr} \\ B_3 &= 16.62 * 20.687 - 15.49 * 21.089 = \$17.15/\text{hr} \\ B_1 + B_2 + B_3 &= \$22.16/\text{hr} \end{aligned}$$

In this test, the actual total benefit B_T is $14936.75 - 14914.56 = \$22.19/\text{hr}$, the reduced production cost from the Base Case to Case 2. B_T is slightly different from $B_1 + B_2 + B_3$ due to the non-linearity of the system as previously mentioned.

The above simulation is a test for one hour. If multiple hours 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 verified that the total benefit in $\$/\text{MVar-year}$ is very comparable to the Var payment to central generators or power factor penalties, if the tie-line congestion is assumed to be a few months.

V. CONCLUSIONS

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

- The economic benefit to utilities from local Var compensation is significant if compared with the payment to central generators or power factor penalties.
- Other entities may have reduced or increased revenues from local Var compensation under each of the three benefit categories. Therefore, the allocation of the installation cost and operation benefit of Var compensators needs further

investigations in the future.

- The major and quantifiable economic benefit may be classified into three categories: reduced losses, shifting reactive power flow to real power flow, and increased transfer capability.
- The economic benefit can be obtained by a set of OPF runs.
- Since the benefit is significant and comparable to the payment to central generators, it will be necessary to include DERs or other local Var sources into future Var markets.
- The separation of the three benefits may be helpful to design future reactive power market and pricing for different components. So, reasonable payment or revenue may be collected and distributed to different market participants.
- This paper assumes a constant Var injection and a fixed location. In the future, an in-depth analysis of different Var sources and locations is needed because they may have different voltage-power characteristics.

Table 1. 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 consumption and fuel cost										
Bus	1	4	6	7						
a (MBtu/hr)	373.500	388.930	253.240	194.280						
b (MBtu/MW*hr)	7.771	7.836	7.573	7.620						
Fuel Cost (\$/MBtu)	2.139	2.093	2.035	2.061						
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 (MW)										
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.)										
$V_{\max}=1.05$ and $V_{\min}=0.95$ for every bus.										

Table 2. Load and Generations 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 3. Base Case Results

System: No Var source, tie lines limit is 348 MVA				
Total fuel cost : 14936.75 \$/hr				
Real power loss: 9.6666 MW				
Active power generation (MW)				
Bus	1	4	6	7
P_G	112.494	200.000	268.423	198.750
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	173.871	174.129	348	

Table 4. Case 1 Results

System: 15 MVar source at Bus 3, tie lines limit is 348 MVA				
Total fuel cost : 14931.56 \$/hr				
Real power loss: 9.4803 MW				
Active power generation (MW)				
Bus	1	4	6	7
P_G	110.609	200.000	270.263	198.608
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	174.735	173.265	348	

Table 5. Case 2 Results

System: 15 MVar source at Bus 3, tie lines limit is 369 MVA				
Total fuel cost : 14914.56 \$/hr				
Real power loss: 9.8826 MW				
Active power generation (MW)				
Bus	1	4	6	7
P_G	89.922	200.000	285.038	204.922
Interface flow (MVA)				
Tie Line	Line 6-2	Line 7-5	Total	
Flow	178.561	190.439	369	

VI. ACKNOWLEDGEMENT

The authors would like to thank Mr. Thomas J. King of Oak Ridge National Laboratory for his comments and suggestions.

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VIII. BIOGRAPHIES

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