8. Voltage deviation with RE

The subject had been dealt for a long time by many people. The author thought that he should rather stability that is dealt by almost nobody. However, many queer opinions had been seen in voltage deviation subject , so the author was forced to study the subject by himself so that the ongoing inadequate proceeding should be stopped.

The first queer opinion is to employ “two way communication” from the beginning. The technique is developing one. It is too aggressive to depend on such not established technology. If development the technology is recognized as an insurance for future, it is reasonable. But people seem to be urged to make up a new business using the technology. As reasonable way, first, it must be examined how far we can go using established techniques. Second, if established techniques are not sufficient, consider new technology. As told later, now three available techniques exist, that is, tap control in distribution transformer, step voltage regulator in distribution network, and constant leading power factor operation in PV.

The second queer opinion is to employ SVC as promising measure as a matter of course for mitigating voltage deviation in distribution network. SVC is an expensive equipment. Even though it is promising, the other more economic measures must be consider first. For example, today’s photovoltaic generation (PV) as interconnecting equipment uses inverter, in which IGBT (Insulated Gate Bipolar Transistor) is adopted. IGBT inverter hardly generate harmful order harmonics because of its high switching frequency. Also the inverter by IGBT can freely generate or absorb both active and reactive power. In other words, PV includes SVC function from the beginning. In spite of the fact, why people insist to add SVC without utilizing IGBT inverter’s splendid and economic function?

The third queer opinion is to operate SVC and PV at constant voltage control. If many equipment under constant voltage control are connected in high resistance and low reactance network such as distribution network, by error of reference voltage setting, large reactive current called as “cross current” appears. In natural inflow hydro power station, number of operating generators is managed suitable for inflow to maintain flow of one turbine is kept in favorable range. For the purpose some generators are connected in parallel to the same bus, and anti-cross current is prepared. Discussers don’t know it, do they? Error in voltage sensor is also a problem. If 2% error exists in 0 to 120V sensor, to maintain voltage 101 to 107 V, measured voltage must be maintained within 101+2.4 to 107-2.4V, that is, 103.4 to 104.6V. Permitted band width is only 104.6 – 103.4 = 1.2V. Compare with 107 – 101V = 6V, It must be said as impractical.

Tap control in distribution transformer

I is the most important voltage control in distribution network. It is a quite economical method, but two defects exist. The first defect is tap changes in step, so smooth control is impossible. For countermeasure tap step band is usually selected as small as 1 to 2%. The second defect is time delay in tap change, so tap cannot follow fast and large voltage deviation. Until now, fast and large voltage deviation had not been appeared. However, by high RE integration, causes that generate fast and large voltage deviation, such as parallel in and shutdown of large wind turbine and output deviation of highly integrated PV, which is examined afterward.

Program control In tap control, it is only tap position that can be controlled. There are only three observed value; time t, substation voltage vector **V**, and substation load current vector **I**. The most primitive control time t and voltage magnitude |**V**|, which is maintained scheduled (by time t) value. The method is called as “program control”.

LDC As high PV (Photovoltaic power generation) integration has become reality, revers power flow (active power flows from PV to system center) in distribution bank is really observed. Reverse bank flow brings 1) issue in protection and 2) negative effect of LDC. Then, reverse bank flow was forbidden for a time.

LDC (Line voltage Drop Compensation) presumes average voltage of loads under thr bank by calculation from 6.6kV bus voltage and bank secondary current, and control tap position so that the presumed average voltage is kept within set band. Thus LDC is clearly a progressed method than does not control load’s voltage but controls substation voltage.

The author noticed that two types of LDC exist, that is, in presuming average voltage, one method employing vector calculation and another method employing scalar calculation. The author named the former as “vector LDC” and the latter “scalar LDC”. Those were presented in panel discussion of 2011 IEEJ Annual Conference on PE[(1)(2)]。 This is the first scene that existence of two different LDCs is known to society. Here, both LDC are introduced and analyzed. Of course problem 2) negative effect of LDC appears only in scalar LDC. Therefore adopting vector LDC, the negative effect problem is solved.

Vector LDC To understand principle of LDC, it is useful to draw structure for realizing its function by hardware. One example is shown in Fig. 8.1. In vector LDC, loads’ average voltage V_{L2} is presumed by vector calculation as follows.

$$\mathbf{V_{L2}} = \mathbf{V_2} - \mathbf{Z_2}\,\mathbf{I_2} \qquad (8.1)$$

This is a replica of the vector calculation in primary side expressed as follows.

$$\mathbf{V_L} = \mathbf{V} - \mathbf{Z}\,\mathbf{I} \qquad (8.2)$$

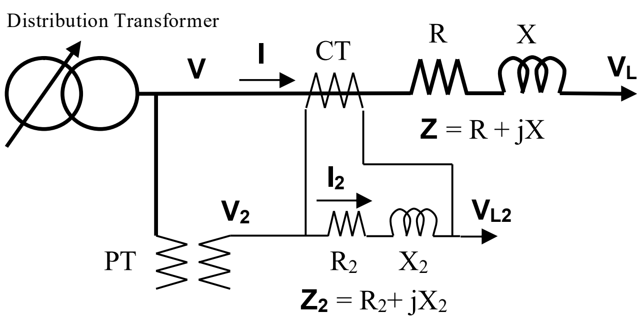

Fig. 8.1 Vector LDC constructed by hardware

$\mathbf{V_2}$ ($\mathbf{V}$), $\mathbf{I_2}$ ($\mathbf{I}$) are voltage and current vector itself obtained from PT or CT. Therefore, it becomes important to set LDC impedance $\mathbf{Z_2}$ ($\mathbf{Z}$) adequately to adequately calculate loads’ voltage $\mathbf{VL_2}$ ($\mathbf{V}$).

Scalar LDC An example of hardware structure to realize scalar LDC is shown in Fig. 8.2. In the structure, loads’ average voltage calculated at secondary of PT and CT $|\mathbf{V_{L2}}|$ is obtained by scalar calculation as follows.

$$|\mathbf{V_{L2}}| = |\mathbf{V_2}| - |\mathbf{Z_2}\,\mathbf{I_2}| \qquad (8.3)$$

This is not a replica calculated at primary side of PT and CT as follows.

$$\mathbf{V_L} = \mathbf{V} - \mathbf{Z}\,\mathbf{I} \qquad (8.2)$$

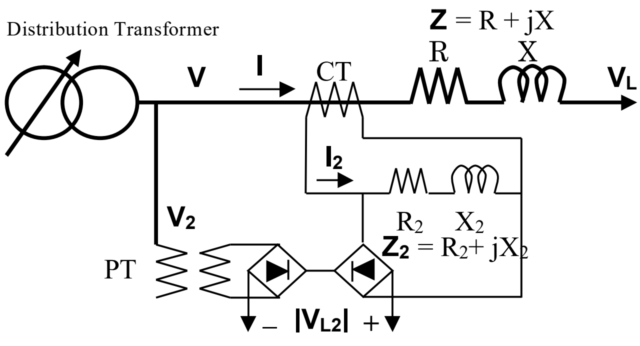

Fig. 8.2 Scalar LDC constructed by hardware

At the secondary of PT and CT, absolute value of loads’ average voltage $|\mathbf{V_{L2}}|$ is calculated necessarily smaller than absolute value of secondary bank voltage $|\mathbf{V_2}|$. Therefore, scalar LDC cannot reproduce the phenomenon. On the contrary loads’ average voltage is assessed as lower than reality, and as the result, tap position is increased. This is the negative effect of LDC, which is an unique flaw of scalar LDC.

Three setting method of vector LDC

Vector LDC must be fed impedance **Z** along path to aggregated load and reference voltage Vref for the load. That is setting of vector LDC. Here, some favorable relationship between **Z** and Vref must exist. If the relationship is not favorable, vector LDC cannot show sufficient performance.

Setting point of vector LDC must vary by loads' distribution aspect. Here as load's distribution, "flat distribution" and "fan form distribution" are introduced. As LDC setting method, "load center method: L" had been used long. The author adds two more methods: "voltage center method: V" and "Y-connection aggregation: Y". "Load center method" uses the voltage at which load amount of front side and rear side becomes equal. "Voltage center method" uses the voltage at which voltage drop is half of that at tail end. "Y-connection aggregation" uses the impedance at which network loss is preserved through aggregation. Hereafter, per unit method is used. Voltage drop is normalized that voltage drop when all loads locate at tail end is 1.

Flat load distribution Concept of flat load distribution is shown in Fig. 8.3. When distribution line is approximated by line, load amount is equal in every small section. Now maximum forward (downward) power is flowing using permitted voltage range fully. Assuming distance from substation is expressed as x, load current amount in small section is expressed as follows.

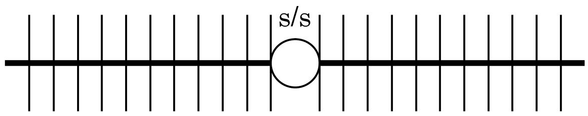

Fig. 8.3 Concept of flat load distribution

$$\varDelta I(x) = 1 \qquad (8.4)$$

Therefore, passing current at location x is expressed as follows.

$$I(x) = \int_{x=x}^{1} \varDelta I(x)\,dx = 1 - x \qquad (8.5)$$

Voltage drop at location x is expressed in negative value as follows.

$$\varDelta V(x) = \int_{x=0}^{x} -I(x)\,dx = \frac{x^2}{2} - x \qquad (8.6)$$

Calculated current, voltage, and loss profile is shown in Fig. 8.4 Also reference impedance and voltage by three LDC setting methods are shown in the figure (V, Y, and P). Normalized permitted voltage range is -0.5 to 0. Here, permitted range of high voltage is assumed as 102 to 106V by conversion (6600V/105V) to low voltage. Normalized -0.5 to 0 corresponds to 102 to 106V by low voltage conversion

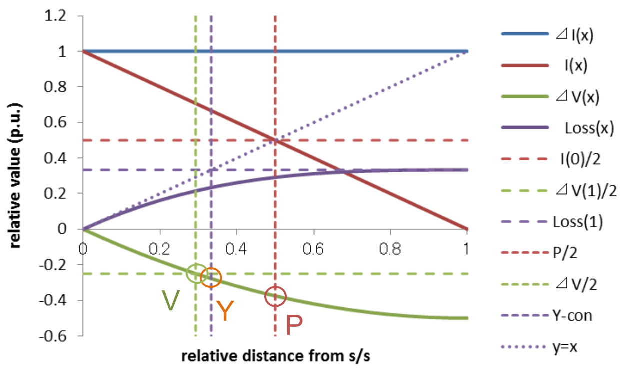

Fig. 8.4 Current, voltage, loss in flat load distribution

In "load center method (P/2)", it is x = 0.5 that corresponds I(x) = 0.5. That is, impedance is set as half of impedance to tail end. Considers voltage drop at x = 0.5: $\varDelta V(0.5) = -0.375$, Vref is, by low voltage conversion,

$$V_{ref} = 106V - (106V - 102V)*(0.375/0.5) = 103V$$

This corresponds to point P in the figure.

However mistaken that "voltage drop is half because load center", voltage reference is set as -0.5 (104V) that is half at tail end: -0.25 (102V), the setting is 1V (low voltage conversion) higher than proper value (103V), system voltage become higher everywhere by 1V.

In "voltage center method ($\varDelta$V/2)", x = (4 – $\sqrt{8}$) /4 = 0.292893 is obtained by solving equation as follows.

$$\varDelta V(x) = \frac{X^2}{2} - x = \frac{\varDelta V(1)}{2} = \frac{-1}{4} \qquad (8,7)$$

Vref is, of course as half voltage drop, 104V, which corresponds point V in the figure.

However mistaken as "load is also half because voltage drop is half" and impedance is set x = 0.5, system voltage become higher everywhere.

In "Y-connection aggregation (Y-con)" total loss from substation to tail end is L(1) = 1/3. As the same loss appears by concentrated load at tail end, x = 1/3. Voltage drop there is calculated as follows.

$$\varDelta V(1/3) = \frac{1}{18} - \frac{1}{3} = \frac{-5}{18} \fallingdotseq -0.277778$$

Therefore, Vref is calculated as follows.

$$V_{ref} = 106V - (106V - 102V)*(0.277778/0.5) = 103.8V$$

As at maximum power flow permitted voltage range (102 to 106V by low voltage conversion) is just fully used, voltage-distance profile shrinks in vertical (voltage) axis making P (in case of load center method), V (in voltage center method), or Y (in Y-connection aggregation method) as pivot. As result in any lighter power flow cases, voltage at any location (x) necessarily stays within permitted range. As stated above, these three setting of vector LDC perfectly operate, if favorable relationship of impedance x and reference voltage Vref is not mistaken.

On the contrary, aspect is much different in reverse power flow. Assumed that there flows the same magnitude of reverse power flow as the maximum forward power flow that just fully use the permitted voltage range. Voltage profile is different by vector LDC setting methods as shown in Fig. 8.5

In reverse power flow, voltage profile $\varDelta$V(x) is vertically turned reverse making P (in load center method), V (in voltage center method), or Y (in Y-connection aggregation method) as pivot.

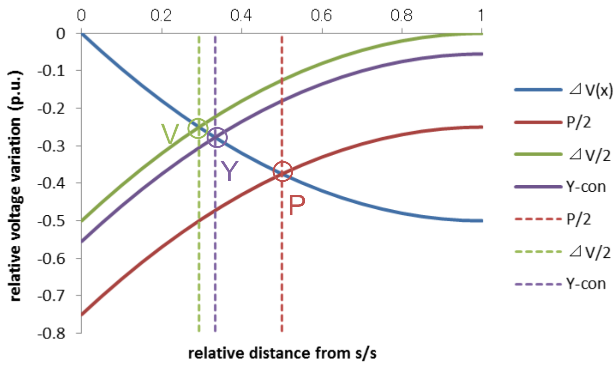

Fig. 8.5 Voltage profile in reverse power flow (flat)

In load center method, a large margin exists at tail end voltage, but on the contrary substation voltage is -0.75 (100V by low voltage conversion), which is far lower than permitted minimum value: -0.5 (102V by low voltage conversion). As $\varDelta$V at P is -0.375, to maintain voltage within permitted range at any location (x), magnitude of reverse power flow must be limited as (0.5 – 0.375) / (0.75 – 0.375) = 0.333 of maximum forward power flow magnitude.

In Y-connection aggregation method, a small margin exists at tail end voltage, but on the contrary substation voltage is -0.555 (101.6V by low voltage conversion), which is slightly lower than permitted minimum value: -0.5 (102V by low voltage conversion). As $\varDelta$V at Y is -0.277778, to maintain voltage within permitted range at any location (x), magnitude of reverse power flow must be limited as (0.5 – 0.277778) / (0.555 – 0.277778) = 0.802 of maximum forward power flow magnitude.

In voltage center method, voltage at tail end is just permitted maximum voltage. Substation voltage also is just permitted minimum voltage. Therefore, magnitude of permitted reverse power flow is equal to maximum forward power flow magnitude. This is a matter of course, because at the pivot V voltage drop is just 1/2 of tail end.

Fan form load distribution Concept of fan form load distribution is shown in Fig. 8.6. A round area fed by a substation is divided radially like pizza, and each division is fed by a feeder. Load distribution is larger at tail end. When distance from substation is expressed as x, load current amount in small section is expressed as follows.

$$\varDelta I(x) = 2x \qquad (8)$$

Therefore, passing current at location x is expressed as follows.

$$I(x) = \int_{x=x}^{1} \varDelta I(x)\,dx = 1 - x^2 \qquad (8.9)$$

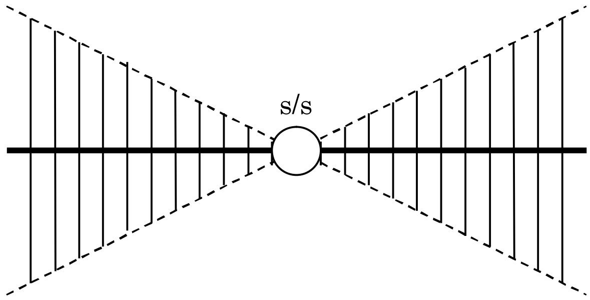

Fig. 8.6 Concept of fan form load distribution

Voltage drop at location x is expressed by negative value as follows.

$$\varDelta V(x) = \int_{x=0}^{x} -I(x)\,dx = \frac{x^3}{3} - x \qquad (8.10)$$

Loss from substation to location x is expressed as follows.

$$L(x) = \int_{x=0}^{x} I(x)^2\,dx = \frac{x^5}{5} - \frac{2x^3}{3} + x \qquad (8.11)$$

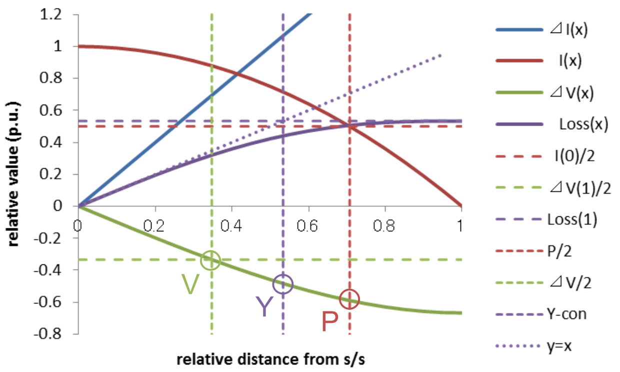

Fig. 8.7 Current, voltage, and loss in fan form load distribution

Calculated profiles of current, voltage, and loss are shown in Fig. 8.7. Also vector LDC setting (impedance (normalized to distance from substation) x and reference voltage Vref) by the three methods are shown.

Normalized permitted voltage range is -2/3 to 0. Here, permitted high voltage is chosen as 102 to 106V by low voltage conversion.

In load center method, x is $1/\sqrt{2}$ that gives I(x) = 1/2. That is, LDC impedance is set as $1/\sqrt{2}$ = 0.707 of impedance from substation to tail end. Voltage drop at the location is $\varDelta V(1/\sqrt{2}) \fallingdotseq$ -0.589256, which is expressed by low voltage conversion as follows.

Vref = 106V – (106V – 102V)*(0.589256 / (2/3)) = 102.5V

It corresponds point P in the figure.

In voltage center method, by solving equation as follows, impedance setting x $\fallingdotseq$ 0.347296 is obtained. Voltage drop at the location is of course half of that at tail end, and Vref is 104V as low voltage conversion.

$$\varDelta V(x) = \frac{x^3}{3} - x = \frac{\varDelta V(1)^2}{2} = \frac{-1}{3} \qquad (8.12)$$

In Y-connection method, loss from substation to tail end is L(1) = 8/15. As the same loss appears by concentrated load at tail end, x = 8/5 ≒ 0.533333. Voltage drop there is ⊿V(8/15) ≒ -0.482765, which is expressed as follows by low voltage conversion.

Vref = 106V – (106V – 102V)*(0.482765 / (2/3)) = 103.1V

It corresponds point V in the figure.

Also in fan form load distribution, as at maximum power flow permitted voltage range (102 to 106V by low voltage conversion) is just fully used, voltage-distance profile shrinks in vertical (voltage) axis making P, V, or Y as pivot. In any lighter power flow, voltage stays within permitted range at any location.

Assumed that there flows the same magnitude of reverse power flow as the maximum forward power flow. Voltage profile is different by vector LDC setting methods as shown in Fig. 8.8.

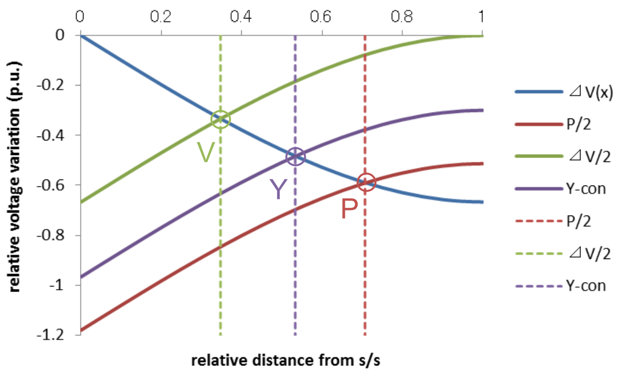

Fig. 8.8 Voltage profile in reverse power flow (fan)

In reverse power flow, voltage profile ⊿V(x) is vertically turned reverse making P (in load center method), V (in voltage center method), or Y (in Y-connection aggregation method) as pivot.

In load center method, a large margin exists at tail end voltage, but on the contrary substation voltage is -1.18 (98.9V by low voltage conversion), far lower than minimum : -0.5 (102V, same). As ⊿V at P is -0.589256, to maintain voltage within permitted range, reverse flow must be limited as (2/3 – 0.589256) / (1.18 – 0.589256) = 0.131 of maximum forward power flow magnitude.

In Y-connection method, a margin exists at tail end voltage, but on the contrary substation voltage is -0.967 (100.2V by low voltage conversion), lower than minimum: -0.5 (102V, same). As ⊿V at T is -0.482765, to maintain voltage within permitted range, reverse power flow must be limited as (2/3 – 0.482765) / (0.967 – 0.482765) = 0.380 of maximum forward power flow magnitude.

In voltage center method, voltage at tail end is just permitted maximum voltage. Substation voltage also is just permitted minimum voltage. Therefore, magnitude of permitted reverse power flow is equal to maximum forward power flow magnitude. This is a matter of course, because at the pivot V voltage drop is just 1/2 of tail end.

Summing up and practicality In two load distribution: 1) flat and 2) fan form, three vector LDC setting methods 1) load center, 2) voltage center, and 3) Y-connection aggregation are examined. Of course, other methods are possible, but are not mentioned here.

Normalizing permitted maximum forward power flow as 1, permitted maximum reverse power flow by the six cases are summed up as Table 8.1. In "Power Academy" homepage LDC is explained as "to maintain voltage at load center". This is "load center

Table 8.1 Permitted maximum reverse power flow

Load distribution	Setting method of vector LDC		
	Load center	Voltage center	Y-connection
Flat	0.333	1.000	0.802
Fan form	0.131	1.000	0.380

method", which show least permitted reverse power flow. Voltage center method enables equal permitted reverse flow as forward flow. Permitted reverse power flow by Y-connection method is so good as 0.9 of forward flow in flat load distribution, but becomes worse as 0.689 in fan form load distribution.

However, laborious method cannot be adopted even if permitted reverse power flow is large. The most laborious one is Y-connection method, in which once laboriously built detailed system is laboriously aggregated. Data for detailed system do not exist. On the contrary, load center method and voltage center method can utilize load distribution and voltage profile in "voltage management dataset" that are already owned by distribution section of every utility. From viewpoint above, voltage center method that has maximum permitted reverse flow and is not laborious is recommended.

Impact of mixed pole transformer tap

In analyses above, tap of pole all transformers was 6600V/105V only. However sometimes to increase possible forward flow, 6750V/105V tap is used around substation and 6450V/105V tap is used around tail end. As the mixed use of tap aims to increase possible forward flow, possible reverse flow decreases.

Here, analyses are performed in some cases. Load is assumed as flat distribution. Normalized voltage drop is already calculated as eq. (8.6), from which polr transformer secondary voltage at location x: VL(x) is calculated as follows.

$$V_L(x) = n(x)\ \{V_L(0) - P\,(x - \frac{x^2}{2})\} \qquad (8.13)$$

Here, n(x) is turn ratio of pole transformer at location x by normalized 6600V/105V as 1. $V_L(0)$ is ople transformer secondary voltage at substation end. P is forward flow at substation end. Permitted voltage is assumed as 102 to 106V.

Load center method In the method, voltage at x = 0.5 is maintained. Three cases as to pole transformer tap is assumed as follows. x_t expresses tap change location.

1. 6600V/105V everywhere.
2. 6600V/105V and 6450V/105V at x_c=0.375 or farther.
3. 6600V/105V and 6450V/105V at x_c = 0.6 or farther.

Voltage profiles at possible maximum forward flow or possible maximum reverse flow are shown in Fig. 8.9. When flow changes, in case 1 (1tap) voltage at L1 is, in case 2 (2tap1) voltage L2is, and in case 3 (2tap2) voltage at L3 is maintained.

Major variables of each case are shown in Table 8.2.

Case 1 enables 8 p.u. forward flow by fully using permitted voltage range 102 to 106V, but in reverse flow, margin remains at high voltage side, and reverse flow is limited as -2.667 p.u..

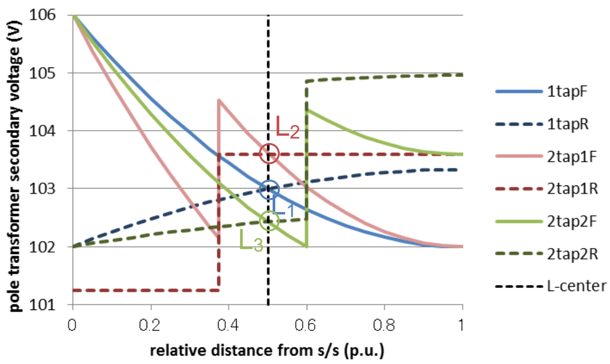

Fig 8.9 Voltage profile by load center LDC setting

Table 8.2 Major variables by load center method

Tap	6600V/105V		x_t = 0.375		x_t = 0.6	
Flow	For	Rev	For	Rev	For	Rev
$V_L(0)$	106	102	106	101.24	106	102
P	9	-2.667	12.636	0	9.5238	-1.143
V_{LMAX}	106	103.33	106	103.60	106	104.96
V_{LMIN}	102	102	102	101.24	102	102

Case 2 enables 12.636 p.u. forward flow by fully using permitted voltage 102 to 106V, but voltage at substation end is lower than minimum 102V. That is, not only in reverse flow but also light forward flow result excessive low voltage. The case is not practical. The reason is that tap change location 0.375 is located farther than voltage maintaining location 0.5.

Case 3 enables 9.5238 p.u. forward flow by fully using permitted voltage range 102 to 106V, but in reverse flow, margin remains at high voltage side, and reverse flow is limited as -1.143 p.u..

Thus, in LDC setting by load center method case, permitted reverse flow is small even if 1 tap case, and becomes very small in two tap mix case.

Voltage center method In voltage center method, voltage at $x = 1 - \sqrt{0.5} = 0.292893$ is maintained.. Pole transformer tap is assumed as 1. and 2. Of the former section.

Voltage profiles at possible maximum forward flow or possible maximum revers flow are shown in Fig. 8.10.When flow changes, voltage at L1 in case 1 (1tap), st Ls in case 2 (2tap1) is maintained.

Major variables in each case are shown in Table 8.3.

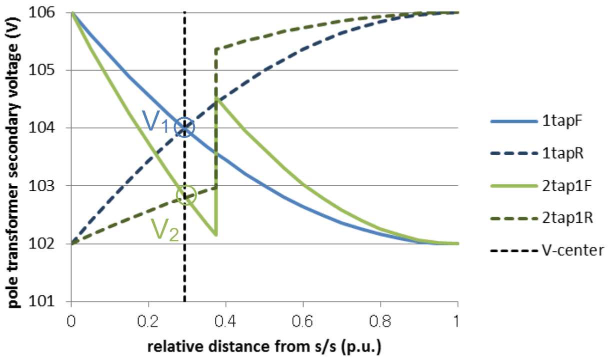

Fig 8.10 Voltage profile by voltage center LDC setting

Table 8.3 Major variables by voltage center method

Case	①all 6600V/105V		②xc = 0.375	
Flow	For	Rev	For	Rev
$V_L(0)$	106	102	106	102
P	8	-8	12.6364	-3.1818
V_{LMAX}	106	106	106	106
V_{LMIN}	102	102	102	102

Case 1 enables 8 p.u. forward flow by fully using permitted voltage range 102 to 106V, and reverse flow is permitted also 8 p.u. using 102 to 106 V range fully.

Case 2 enables 12,6364 p.u. forward flow by fully using permitted voltage range 102 to 106V. In light flow, voltage at substation is kept within permitted range. The reason is that as location of LDC reference voltage is shifted to x = 0.292893, location of tap change can set as $x_c = 0.375$, and voltage at x_c can be higher than voltage at tail end. Also in reverse flow case, permitted voltage range 102 to 106V is fully used, but mixed two taps convenient for forward flow, but in reverse flow, reverse flow is limited as -3.1818 p.u., which is better than load center setting case.

Table 8.4 Possible maximum forward and reverse flow

LDC setting	All 6600V/105V		Mixed with 6450V/105V	
	For	Rev	For	Rev
L-center	1	-.33333	1.190475	-0.14288
V-center	1	-1	1.57955	-.39773

Thus LDC setting by voltage center method enables equal reverse flow as forward flow in one tap pole transformer case, and even in two tap mixed case, reverse flow limit certainly decrease but better than setting by load center method.

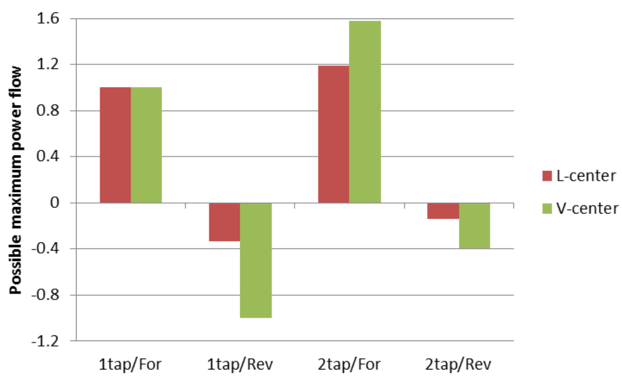

Fig. 8.11 Possible maximum forward and reverse flow

Summary By case studies above, in case of only one pole transformer tap possible maximum forward flow was 8 p.u. without affected by LDC setting method. So, it is taken as reference flow (1.0), possible forward and reverse flow are summarized as Table 8.4.

That is expressed as column graph as Fig. 8.11. Permitted flow by voltage center setting is always better than that by load center method in both forward and reverse flow, especially better in reverse flow. Today, when reverse power flow has become reality, unavoidably adopted vector LDC is recommended to be set by voltage center method.

Besides, even in forward flow when two tap of pole transformer are mixed, permitted flow is strongly limited in load center setting because permitted voltage range is not fully used. On the contrary, reverse flow by voltage center setting is not limited by such a reason, and much more reverse flow is permitted.

Thus, as vector DC setting, voltage center method that is presented by the author is far better than load center method that had been regarded as a matter of course and adopted generally.

Mixed tap on pole transformer has another problem. For example when a new distribution substation is build, the location is far from any existing substation. Around there pole transformer tap is perhaps 6450V/105V. There a new substation is build, tap should be changed to 6600V/105V. However, tap change on pole transformer needs outage, and is not accomplished for a long time. So, at least one utility uses only 6600V/105V tap, and SVR (Step Voltage Regulator) is used instead of 6450V/105V tap. Since high PV integration era, when reverse flow in distribution bank is not rare, has come, mixed tap on pole transformer should be solved in a long time range.

Vector LDC does not show negative effect even in reverse flow, it must be a promising technique in high PV integration era. However as time being, since different taps are mixed on pole transformer, effect of vector LDC is somewhat limited. Therefore, cooperation with the other technique is favorable. As a candidate "constant leading power factor operation[5][6]" on PV that has been recommended by the author is promising. Because the leading power factor maintains distribution network voltage without moving distribution transformer tap, so does not claim LDC any contribution.

SVR

SVR is a single winding transformer, whose tap is changed so as to control tail end side voltage, and has a very long history. Introducing a typical SVR, it has 4 taps for voltage boosting side and 3 taps for voltage suppressing by 100V step.

It is quite important in voltage control by SVR that substation side and tail end side should be distinguished. Because substation side voltage does not change but tail end side voltage changes by tap change. Distribution network very often take temporary structure because of maintenance and so on. Then, it is quite possible that SVR's substation side and tail end side are changed. In those days without RE, only forward flow existed. So, seeing flow direction substation and tail end side were distinguished and direction of SVR control was changed if needed. However today, reverse power flow can also appear by RE, such a distinguish method is no more practical. Thus, many new methods are now being developed.

A method focusing difference of impedance seen from SVR to both sides is believed as promising. However, it is questionable at which timing the impedance should be measured? The author thinks another method as practical. That is, like active anti-islanding function of RE, small signal is continuously injected from SVR to system. The signal current mainly flows to substation side, and both sides are distinguished. Also as another primitive method that operator sets direction by remote control system should be taken into consideration.

Constant leading power operation on PV[5][6][7]

There are two kinds of measures for voltage rise due to high PV integration. The two stated above is done at system side, and this is done at PV side.

Loading and lagging power factor Before major discussion, it must be re-learn what are "leading power factor" and "lagging power factor". In Japan grid code ant texts such an expression as "leading power factor seeing from system side" is seen very often. However in truth, leading or lagging power factor has no relation with seeing direction. It is possible that writers of grid code and texts do not correctly know power factor and reactive power. Here, correct knowledge are shown.

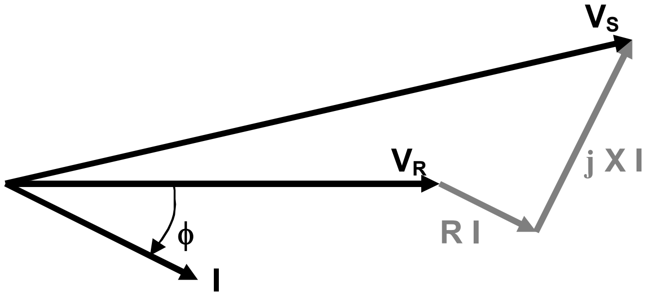

Fig 8.12 Vector diagram of sending and receiving voltages

Every texts shows Fig. 8.12 as vector diagram of voltage at sending and receiving ends. In the figure phase of current vector **I** is lagging by ϕ than phase of receiving end voltage $\mathbf{V_R}$. As current phase is lagging, reactive power in such condition is called as "lagging reactive power", and such power factor is called as "lagging power factor".

In electric power circuit, complex power whose real part means active power and imaginary part means reactive power. The definition is made as product of voltage **V** and conjugate current **I***, that is, **V I***. Taking phase of voltage vector as reference, $\mathbf{V} = V$, $\mathbf{I} = I(\cos(-\phi) + j\sin(-\phi))$. Therefore, complex power is expressed as follows.

$$P + jQ = V I^* = V I(\cos(-\phi) + j\sin(-\phi))^* = V I(\cos(-\phi) - j\sin(-\phi))$$
$$= V I\cos\phi + j VI\sin\phi$$

Thus, $P = V I\cos\phi$, $Q = V I\sin\phi$ are conducted. P and Q are positive. Therefore in power circuit, lagging reactive power is expressed positive. The origin is that complex power was defined as **V I***. If current phase is leading than voltage phase, Q takes negative value. Thus, it will be understood that lagging power factor means $Q/P > 0$, and loading power factor means $Q/P < 0$. Here, such adjective as "seen from system side" never appear. Further saying, the author dislikes such expression as "loading power factor XX %". Physical meaning seems thin. If technical term "power factor" must be used, the author would express "Q = -0.3P (almost lagging 95% power factor)".

Voltage drop Using vector diagram, and taking receiving end voltage $\mathbf{V_R}$ as phase reference, sending end voltage $\mathbf{V_S}$ is strictly calculated as follows.

$$\mathbf{V_S} = V_R + (R + jX)I(\cos\phi - j\sin\phi) = V_R + (R I\cos\phi + X I\sin\phi) + j(X I\cos\phi - R I\sin\phi)$$

$\mathbf{V_S}$, as its imaginary part is relatively smaller than real part, its magnitude is approximately expressed as follows.

$$V_S \fallingdotseq V_R + R I\cos\phi + X I\sin\phi$$

As active and reactive power at receiving end are: $P_R = V_R I\cos\phi$, $Q_R = V_R I\sin\phi$, and voltage is around 1,

$$V_S \fallingdotseq V_R + R P_R + X Q_R$$

Voltage drop is expressed as follows approximately.

$$\Delta V = V_S - V_R \fallingdotseq R P_R + X Q_R$$

Thus, familiar approximate equation is conducted.

While here it is recognized that, if it is possible QR/PR = -R/X, results $\Delta V \fallingdotseq 0$. That is, loading power factor (Q/P < 0) has function to reduce voltage drop (rise). If REs and loads operate at leading power factor, voltage deviation in distribution network is considerably mitigated. Although leading power factor is impractical, as high power factor customers are well treated, power factor of existing customers is considerably high in Japan. Although joining RE has original sin as output fluctuation, has great possibility to become “good citizen” by reducing voltage deviation (including very fast fluctuation) using “constant leading power factor” operation.

Constant power factor operation has been used long and widely in hydro power station, and has been operated well. Cross current such as constant voltage control never occurs. However, what is used in hydro power is “lagging constant power factor” operation. The purpose is to supply reactive power that are consumed in reactance of network so that additional capacitor is not needed to compensate reactive loss. Of course generator voltage rises at high output, but it is already taken in consideration by such measure that main transformer of hydro power station makes generator side voltage lower by around 5% at no load condition by tap setting. However, control character of constant lagging power factor is not different from that of leading power factor, and in truth, some hydro power adopt leading constant power factor because of difficulty in voltage rise. So, leading constant power factor operation is positioned as conservative technique.

Simulation on standard distribution network

Searching IEEJ transactions with “PV” and “voltage rise”, seven papers performing voltage calculation in distribution system were found. Six show no sign of modeling distribution transformer or transmission line. One certainly connects three feeders to 10MVA distribution transformer whose reactance is 7.5% at 10MVA base, but load of a feeder is 3MVA, 0.9 power factor, 0.2 demand ratio, therefore 3 feeder’s total load (that is bang flow) is only

3 feeder × 3 MVA × 0.9 × 0.2 = 1.62 MW,

which is too small compared to distribution transformer size (10MVA).

These seven neglect or underestimate HV (66kV or higher) side impedance including distribution transformer.

The author calculated impedance of 66kV or existing system is shown as follows in peak demand base.

HV system	0.005 + j 0.115
Distribution network	0.030 + j 0.060
Sum	0.035 + j 0.175

Reactance, through which reactive power affects on voltage, is much larger in HV system than distribution network. The reason is that distribution voltage in Japan is rather low as 6.6kV than 22kV class in most countries, and short circuit current in Japan is limited as 12.5kA for safety. Thus, reactance of most frequently used 20MVA distribution transformer must be 20MVA / ($\sqrt{3}$*6.6kV*12.5kA) = 0.13996p.u. or higher at self-capacity base. Since usual 66kV class transformer used in such as hydro power station has around 7%, distribution transformer in Japan has extremely high reactance. Therefore in Japan, voltage deviation is larger in HV side than in distribution network.

To compensate the deviation, “tap control” on distribution transformer sand “reactive power control” on PV contribute much. These control affects distribution voltage regulation very much. However, underestimation of HV side reactance estimates these contribution much smaller, and excessive reactive control is added, and excessive cost and negative effects are brought.

Here, based on realistic distribution system model consists of HV system and distribution network, voltage calculation with much PV is performed and compared with underestimating HV reactance case.

Impedance introduced above is at peak demand base. For use in voltage calculation and simulation, they are converted to 10MVA base values. For the purpose many data and knowledge are needed as shown below.

HV side impedance Loading of 20MVA distribution transformer, which is used by the largest number when classifies by capacity, is around 0.7, that is, peak demand is around 14MW. Therefore, high voltage (HV) side impedance Z_H is converged to 10MVA base as follows.

$$Z_H = (0.005 + j\ 0.115) * (10MVA / 14MW) = 0.0036 + j\ 0.082$$

As impedance of 20MVA distribution transformer is around j 0.072, it is found that a large part of Z_H is derived from distribution transformer.

20MVA distribution transformer usually five feeders of OC150sq size. If the five is same, modeling one feeder under impedance $5Z_H$ will the same result of modeling five feeders under impedance Z_H. Such efficient way is sometimes seen, but it must be remember that $5Z_H$ must be used instead of Z_H.

Peak demand of one feeder is 2.8MW. The amount seems rather small for OC150sq, but there is around 1.2 diversity between one feeder and power system 1. Therefore, peak demand as one feeder is calculated as follows.

$$2.8\ MW * 1.2 = 3.36\ MW$$

The value is beyond 80% of operational limit 4MW, so recognized as reasonable level.

Distribution network impedance In 1980 distribution network loss composition ratio[8] was investigated by central three utilities of Japan. Composition ratio was shown as “P loss” in Table 8.5. Among them pole transformer iron loss 0.3 is parallel loss, and never affects series impedance, so omitted. Total of the other element is 0.7. Iron loss is reduced in s long time by shifting piling core to cut core, but the other equipment is not different from old days in hardware and operation, the composition ratio is still available today.

Multiplying P loss to X/R ratio, Q loss is obtained. The total becomes 1.4. Therefore, X/R ratio of allover distribution network impedance is 2.0, which agrees with X/R ratio of that: 0.030 + j 0.060 by aggregation. By proportional calculation so that all network impedance becomes to 0.030 + j 0.060, impedance of each component is calculated as Table 8.6.

Table 8.5 Composition ratio of distribution network loss

	P loss	X/R ratio	Q loss
MV wire	0.4	2.5	1.0
Pole Tr iron	(0.3)		
Pole Tr copper	0.1	3.0	0.3
LV & drop wire	0.2	0.5	0.1
Total	0.7		1.4

Table 8.6 Distribution network impedance at peak demand base

	R	X/R ratio	X
MV wire	0.01714	2.5	0.04285
Pole Tr iron			
Pole Tr copper	0.00429	3.0	0.01286
LV & drop wire	0.00857	0.5	0.00429
Total	0.030		0.060

Impedance of MV cable In general method middle voltage (MV) distance (26000km in Hokuriku region) is divided by number of feeders (around 2000 in Hokuriku region). Around 13km is obtained as the answer. However by the method, distance of branch is counted, and the answer is quite larger than reality. Numerous other microscopic investigation had been held. However, the author cannot believe them by reason as follows.

1) What is recognized as feeder distance? Method and its verification is not shown.

2) Whole investigation of around 500000 feeders in Japan was not held.

3) No security on random sampling exist in sampling investigation.

Therefore, the author searched macroscopic substitution method. Inhabitable area (4300km^2 in Hokuriku) is divided by number of distribution substation (around 190 in Hokuriku), 22.6km^2 is obtained as answer. Recognizing the answer area as square, its side length is 4.8km, and half of its diagonal is 3.4km. These are quite smaller than the answer before (13km) but reflect reality. However, the method uses parameter out of distribution network data is used, therefore, is not adopted by distribution section of utilities.

Here, structure shown in Fig. 8.13 is assumed and used as model. Since impedance of only MV wire is calculated here, pole transformer to tail end are omitted. Each feeder has five section. The first section has no load. The other four section has 1/4 of feeder load (P_L) in flat distribution. By aggregation omitting pole transformer and tail end, model of each section is so obtained. MV cable is OC150sq in the third section or substation side, and is OC80sq in the fourth section or tail end side. Impedance of MV is calculated using per km impedance as follows at 10MVA base.

OC150sq	0.0321 +j 0.0780
OC80sq	0.0600 +j 0.0822

Here assumed feeder distance as 6km, impedance of aggregated distribution network was calculated as 0.0796 + j0.1827 at 10MVA base. As feeder load P_L is 2.8MW at power system peak demand, at its base MV line impedance is calculated as follows.

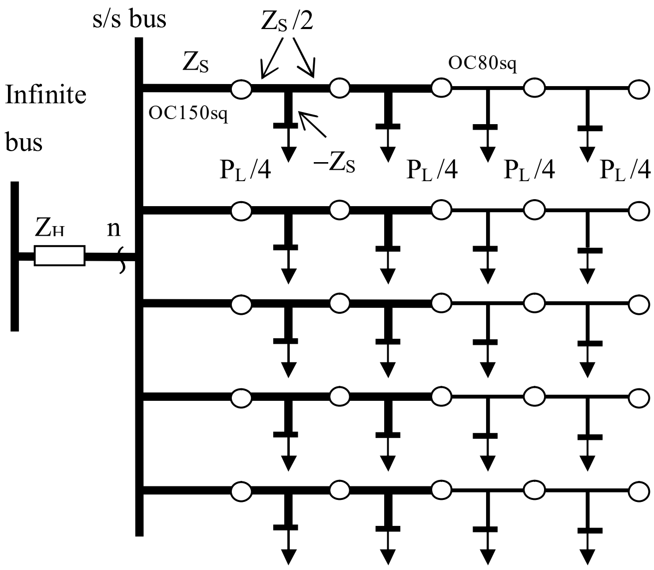

Fig. 8.13 Structure of the model distribution system

$$Z_M = (0.0796 +j\ 1827) * (2.8MW/10MVA) = 0.0223 +j\ 0.0512$$

If feeder distance is assumed as 4.2km instead of 5km, the impedance becomes as follows and agrees with Table 2.

$$Z_M = (0.0223 +j\ 0.0512) * (4.2km/5km) = 0.0187 +j\ 0.0430$$

Therefore, feeder distance is assumed as 4.2km and section distance is assumed as 0.84km here. The distance 4.2km is near the side length 4.8km, which was conducted by another macroscopic method.

Impedance of pole transformer and tail end From table 8.6, series impedance of pole transformer, LV line, and drop wire Z_T is 0.01286 + j 0.01715 at peak demand base. As peak demand of a section is 0.7MW, the impedance is calculated as follows at 10MVA base.

$$Z_T = (0.01286 + j\ 0.01715) * (10MVA/0.7MW) = 0.1837 + j\ 0.2450$$

Thus, one section in distribution network is modeled as Fig. 8.14. Nominal voltage is 6600V for MV and 100V for LV (low voltage). Pole transformer's off nominal tap ratio is 1.05.

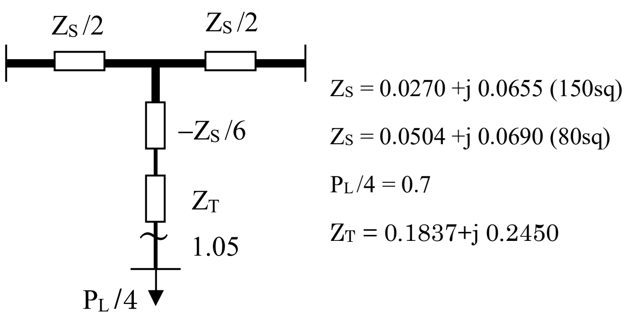

Fig. 8.14 Model of each section

Favorable PV power factor Here adopted "vector LDC" on distribution transformer tap control and "constant leading power factor" on PV reactive power control. They are superior in cost performance. Favorable power factor of PV is calculated as follows.

Impedance of realistic distribution system model were conducted as follows.

HV side	$Z_H = 0.005 + j\,0.115$
MV wire	$Z_M = 0.0187 + j\,0.0430$
Pole transformer and tail end	$Z_L = 0.01286 + j\,0.01715$
Total	$Z = R + j\,X = 0.03656 + j\,0.17515$

PV is assumed to locate at load bus. When PV's active and reactive power changes are ΔP and ΔQ, it is ideal if PV voltage change ΔV becomes as follows.

$$\Delta V = R\,\Delta P + X\,\Delta Q = 0$$

Then, favorable relationship between ΔP and ΔQ is obtained as follows.

$$\Delta Q\,/\,\Delta P = -R\,/\,X = -0.03656\,/\,0.17515 = -0.209$$

It is found that light leading power factor around Q/P = -0.2 (around leading 98% power factor) is favorable.

It must be noticed that in the Q/P ratio PV voltage is maintained without distribution transformer tap change. Therefore, even if fast and large PV output change occurs, voltage change is quite mitigated. For the purpose, "vector LDC" that maintain load and PV voltage constant must be adopted. If "program control (PGC)" that maintains substation bus voltage constant is adopted, bus voltage decreases by PV's constant leading power factor operation, and tap position may rise, thus fruit of constant leading power factor operation may be considerably spoiled.

Here, according to the anxiety mentioned above, the mistaken model that uses HV side impedance Z_H for only one feeder is examined. Impedance is listed up as follows.

HV side	$Z_H = 0.005 + j\,0.115$
MV wire	$Z_M = 0.0935 + j\,0.2150$
Pole transformer and tail end	$Z_L = 0.0643 + j\,0.08575$
Total	$Z = R + j\,X = 0.1628 + j\,0.41575$

Ideal PV power factor is wrongly calculated such as heavy leading as $\Delta Q\,/\,\Delta P = -R\,/\,X = -0.1628\,/\,0.41575 = -0.392$ (around 93% leading).

Simulation of slow output change

Simulation is held on the realistic distribution system model that were already built. For reducing calculation amount, one feeder is modeled under impedance $5Z_H$. Tap is modeled at tail of $5Z_H$ as 66.35kV±7.5kV (17tap), ±0.012 dead band, 0.08 pu.*sec integral time constant.

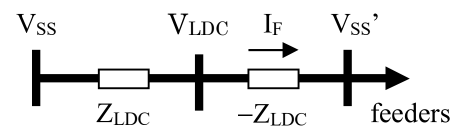

Fig. 8.15 An idea for modeling LDC by deta

"Vector LDC" is modeled as tap control. CRIEPI V-method does not prepare the function. Because in those days when the method were developed vector LDC was not generally known in Japan. However, the function can be modeled by an invention on data as shown in by Fig. 8.15. That is, series two impedances Z_{LDC} and $-Z_{LDC}$ are inserted between substation bus (V_{SS}) and the first section (V_{SS}'). No difference appear outside. LDC voltage, which is the voltage between the two impedances, is calculated as follows.

$$\mathbf{V_{LDC}} = \mathbf{V_{SS}} - \mathbf{Z_{LDC}}\,\mathbf{I_F}$$

Therefore, setting as follows, V_{LDC} is weighted average load voltage. It is "vector LDC" that control tap so that

V_{LDC} is maintained to reference voltage.

$$\mathbf{Z_{LDC}} = \mathbf{Z_M} + \mathbf{Z_L}$$

The author named the control “vector LDC” because it performs vector calculation.

By the way, “scalar LDC” cannot be modeled by invention on data.

As strength of PV’s constant leading power factor, Q = -0.2P and Q = -0.4P are taken. The former is optimal when Z_H is correctly modeled. The latter is optimal when Z_H is wrongly too small (1/5) modeled.

As slow change of PV, PV output in a section is assumed to increase from 0.02 to 0.1 during 10 min to 40 min. Distribution transformer tap changer can sufficiently follow the change.

Modeling correct Z_H　One feeder is modeled under HV side impedance $5Z_H$ = 0.025 + j 0.575. Feeder power flow in case of PV’s leading power factor is Q = -0.2 P is shown in Fig. 8.16. Power flow changes from 0.2 (forward) to -0.12 (reverse).

Then, voltages in various point and distribution transformer tap position are shown in Fig. 8.17. Substation voltage (Vss) decreases, but tap does not rise. LDC voltage (VLDC) slightly rises during 30min until power floe decreases to zero by “voltage rise by reduced reactive power loss due to decreasing flow magnitude”, which is not considered in approximated analysis, and turns to slight decline after 30 min. The result should be said adequate for reactive power control.

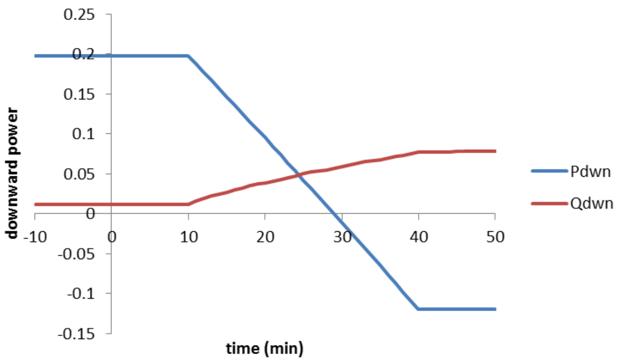

Fig. 8.16　Slow power flow change (correct Z_H, Q= -0.2P)

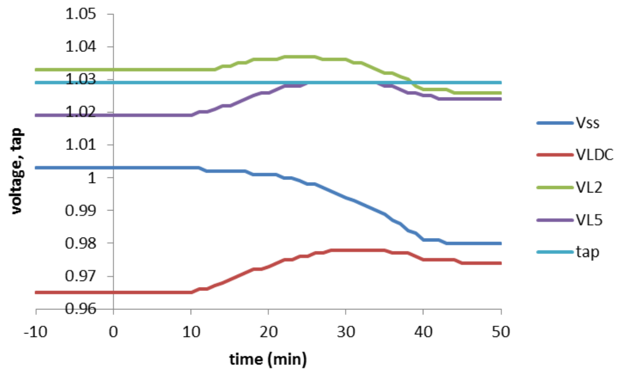

Fig. 8.17　Voltage and tap change (correct Z_H, Q= -0.2P)

Load voltages in the second and fifth section: V_{L2} and V_{L5} almost follows V_{LDC} and their change is small. It is found that such a large PV power change can be managed by vector LDC and PV’s leading power factor in average and realistic distribution system model. However, these voltage s are weighted average of section, and individual load voltage scatters around average. It is a matter of course that detailed model is needed for detailed analysis.

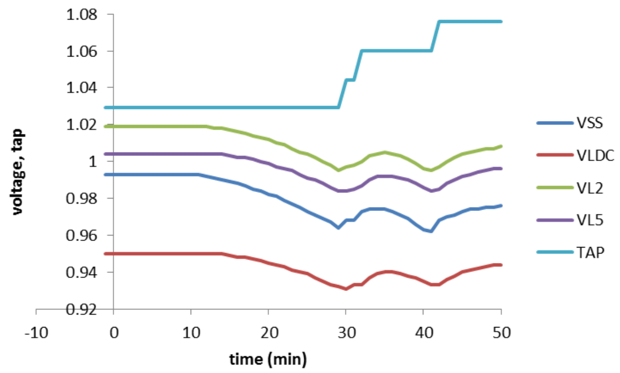

Fig. 8.18　Voltage and tap change (correct Z_H, Q= -0.4P)

In case of PV’s leading power factor is Q = -0.4P, load voltages and tap position are shown in Fig. 8.18. Voltages greatly drop and lifted by tap position rise. This means that reactive power control by PV’s constant leading power factor operation is over compensation.

Modeling too small Z_H　One feeder is modeled under HV side impedance Z_H = 0.005 + j0.125. When PV’ power factor Q = -0.2 P, voltages and tap position become as Fig. 8.19. LDC voltage and load voltages rise, but substation bus voltage does not drop much, because HV side impedance that mainly form the voltage drop is too small modeled. By rising LDC voltage, tap position goes gown. This means that reactive power control by PV's constant leading power factor operation is under compensation.

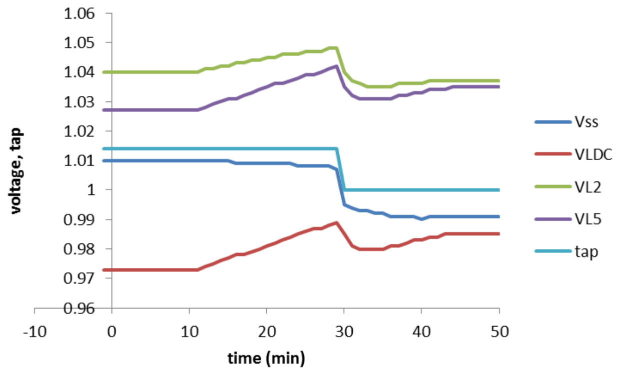

Fig. 8.19 Voltage and tap change (small Z_H, Q= -0.2P)

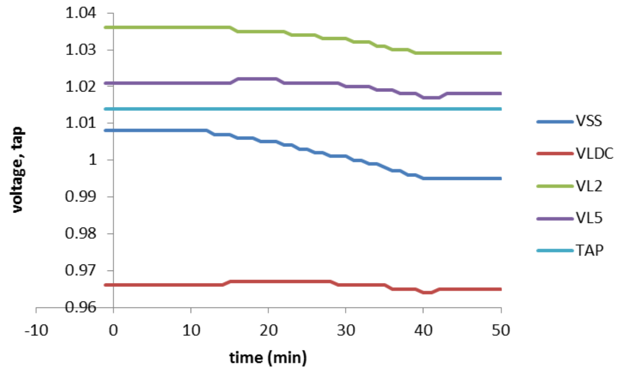

Fig. 8.20 Voltage and tap change (small Z_H, Q= -0.4P)

When PV's power factor is Q = -0.4P, voltages and tap position become as Fig. 8.20. LDC voltage and load voltages slightly reduce, substation voltage reduced a little more, but tap position does not move. This means that reactive power control by PV's constant leading power factor operation is adequate.

On the four cases above, maximum change of load voltage V_{L2} and V_{L5} by time are compared in Table 8.7. Small voltage changes appear in case of adequate Z_H and Q = -0.2P and in case of too small Z_H and Q = -0.4P. On the contrary large voltage changes appear in the other two cases. Especially in case of adequate Z_H and Q = -0.4P, maximum voltage change appears. This means that excessive PV's leading power factor in existing distribution system brings harmful side effect. It is matter of course that too small Z_H results smaller voltage change.

Table 8.7 Maximum voltage change (p.u.)

	Adequate Z_H	Too small Z_H
Q = –0.2P	0.010	0.015
Q = –0.4P	0.024	0.007

Simulation of fast fluctuation

Using the same model of former section, as fast output fluctuation, PV output three times goes and returns 0.02 and 0.1 by 2 min period from 2 min. Tap cannot follows the fast variation.

Modeling correct Z_H One feeder is modeled under $5Z_H = 0.025 + j0.575$. When PV power factor is Q = -0.2P, feeder flow variation is shown in Fig. 8.21. Flow severely varies between 0.2 (forward) and -0.12 (reverse).

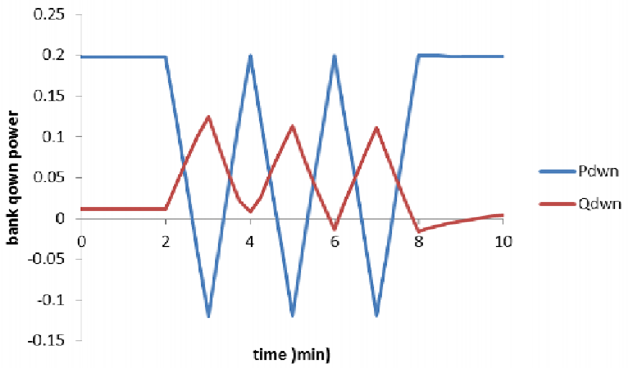

Fig. 8.21 Past power flow change (correct Z_H, Q= -0.2P)

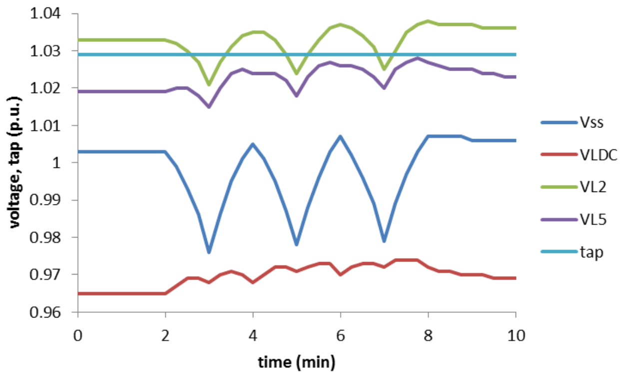

Fig. 8.22 Fast voltage change (correct Z_H, Q= -0.2P)

Then voltages and tap position vary as Fig. 8.22. Tap does not move. Substation voltage varies much, but load voltages and LDC voltage does not vary much. The result means that PV's constant leading power factor operation is adequate as reactive power control. Thus in average and realistic distribution system model, vector LDC and PV's constant leading power factor can manage such a fast and large PV output fluctuation that cannot be compensated by tap change.

In case of PV's leading power factor is Q = -0.4P, load voltages and tap position are shown in Fig. 8.23. Tap does not move. Voltages change is large especially at low side. This means that reactive power control by PV's constant leading power factor operation is over compensation.

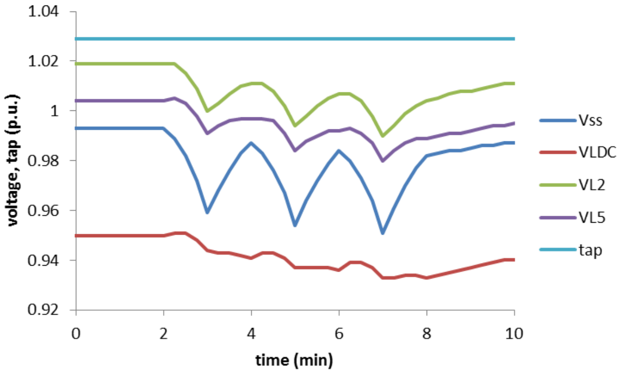

Fig. 8.23 Fast voltage change (correct Z_H, Q= -0.4P)

Modeling too small Z_H One feeder is modeled under HV side impedance $Z_H = 0.005 + j0.125$. When PV' power factor Q = -0.2 P, voltages and tap position become as Fig. 8.24. Tap does not move. Voltages change is large especially at high side. This means that reactive power control by PV's constant leading power factor operation is under compensation.

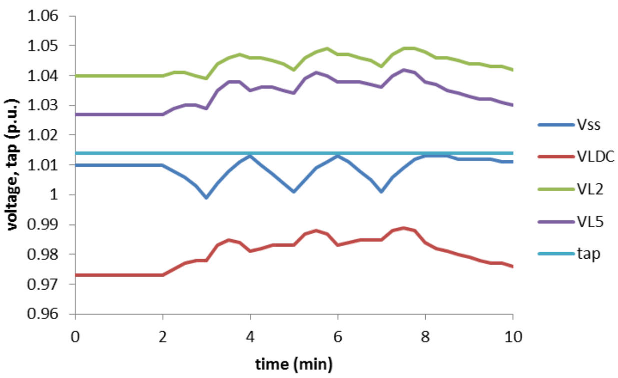

Fig. 8.24 Fast voltage change (small Z_H, Q= -0.2P)

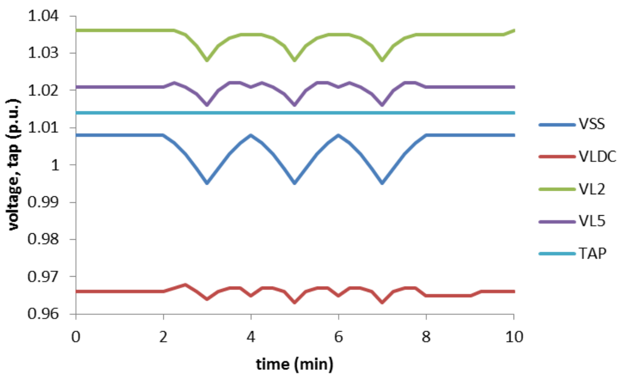

Fig. 8.25 Fast voltage change (small Z_H, Q= -0.4P)

When PV's power factor is Q = -0.4P, voltages and tap position become as Fig. 8.25. LDC voltage and load voltages slightly reduce, substation voltage reduced a little more, but tap position does not move. This means that reactive power control by PV's constant leading power factor operation is adequate.

On the four cases above, maximum change of load voltage V_{L2} and V_{L5} by time are compared in Table 8.8. Small voltage changes appear in case of adequate Z_H and Q = -0.2P and in case of too small Z_H and Q = -0.4P. Large voltage changes appear in the other two cases. Especially in case of adequate Z_H and Q = -0.4P, maximum voltage change appears. This means that excessive PV's leading power factor in existing distribution system brings harmful side effect. It is matter of course that too small Z_H results smaller voltage change.

Table 8.8 Maximum voltage change (p.u.)

	Adequate Z_H	Too small Z_H
Q = –0.2P	0.012	0.015
Q = –0.4P	0.029	0.008

Since high PV integration became realistic, many voltage calculation on distribution system has been performed.

However, except by the author(5)(6)(7)(8), they neglect or underestimate HV side impedance. Also no example that explain origin of distribution system model and parameters minutely.

Here first, average and realistic distribution system model is derived by using various data not limited in distribution section. Average feeder distance is assessed as 4.2km, which is impressed rather shorter. Most articles up to now assumed longer distance, so caused excessive anxiety on voltage change due to PV.

Also here, case that HV side impedance Z_H is correctly modeled and case that Z_H is much smaller modeled are taken into consideration. Simulation is held in Q = -0.2P case and Q = -0.4P case, with slow large and fast large PV output change. As the result, in case Z_H is correctly modeled Q = -0.2P is favorably assessed. On the contrary, in case Z_H is much smaller modeled Q = -0.4P is favorably assessed. Thus, conclusion varies much by used distribution system model, so it is fatally important to build adequate model.

Especially in slow large change in case of correctly modeled Z_H is and Q = -0.4P leading power factor, PV's reactive power control becomes over compensation, and harmful side effect that tap rises and rises is seen. PV's constant leading power factor operation is certainly a powerful and economical countermeasure for distribution voltage maintenance, but excessive use results harmful side effect and forces customers additional cost of capacity increase. It must be noticed that verification distribution system model is fatal in distribution voltage calculation.

High PV integration in existing distribution system(6)

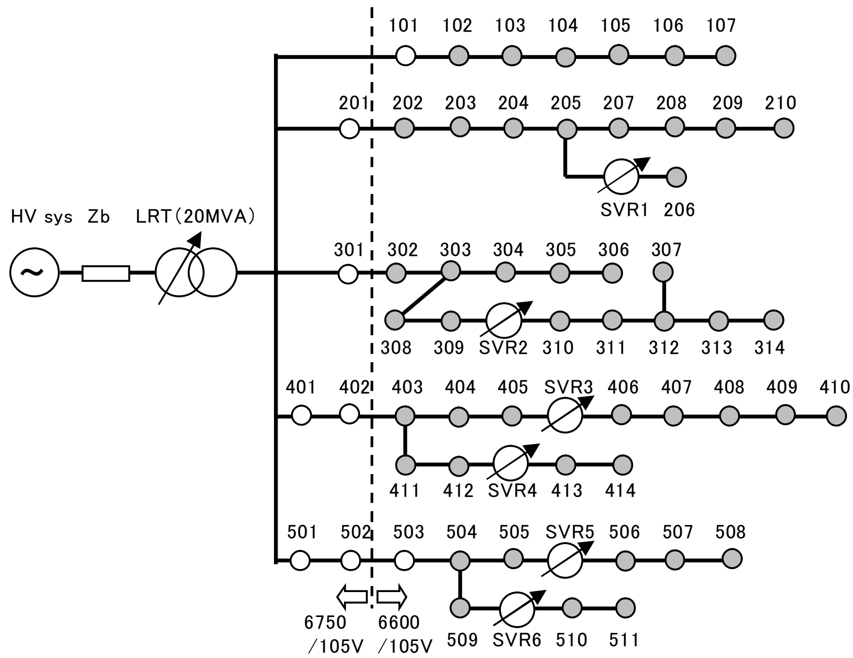

Fig 8.26 Structure of an existing distribution system

Voltage aspect at high PV integration is presumed using existing distribution system as Fig. 8.26. One feeder is divided into several to several teen sections, which are aggregated by "Y-connection method(3)". The distribution system has many light customers, so PV will highly penetrates if strategy that PV is mainly adopted in residence succeeds. Bank becomes reverse flow when PVs fully generate.

Before calculating PV impact, propriety of calculation is verified. Collation of calculated and measured in no PV case is shown in Fig. 8.27. CRIEPI V-method is used for simulation. In most time period error is almost zero. In some time period ±1% or a little more error appears. It is caused mainly by time error of tap operation. The reason of good reproduction is that voltage source is set in HV system, and impedance from the voltage source to secondary of distribution transformer with tap changer. If the model is further simplified, such good reproduction cannot be obtained. Of course, recorded active and reactive power at secondary is delivered to each section, and MV capacitors at customers are taken into consideration.

In most distribution voltage calculation, fictitious distribution system model is used, or propriety is not verified by measured data, if existing system is modeled. The author thinks that such insincere attitudes have been spoiled reliability of calculation and simulation in distribution system.

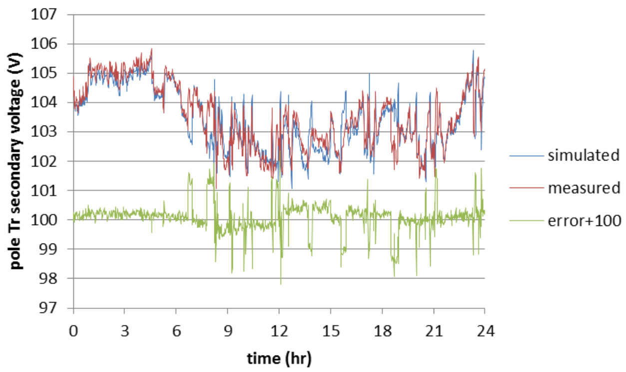

Fig. 8.27 Reproduction of distribution network voltage

In the existing system model, cases that PV operates at Q = 0 or Q = -0.2P, cases that tap is controlled by program control or vector LDC are taken into consideration. Totally 2 * 2 = 4 cases are calculated in 30 min step and the result is shown in Fig. 8.28. PV output in fine day is used. Smoothing effect is not considered. In the figure, maximum, minimum, and substation voltage are shown as pole transformer secondary voltage conversion. In only one case where PV is Q = -0.2P operation and tap is controlled by vector LDC voltage stays within 107V during one day.

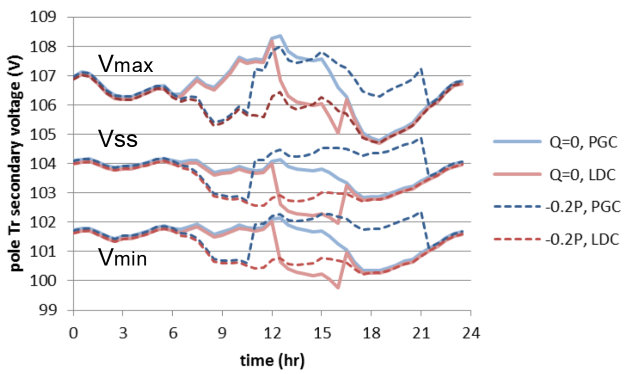

Fig. 8.28 Voltage profile by control method

Effect of leading power factor in fast fluctuation[6]

Up to here PV's fast output change is not modeled. However, PV sometimes generates fast output change. Since such as PGC and LDC maintain voltage by tap control, they cannot follow PV's fast output change, and as the result, considerable voltage deviation remains.

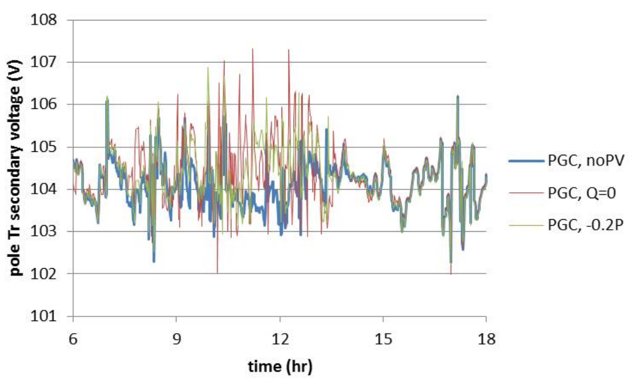

Fig. 8.29 Voltage deviation by PV's fast output change (PGC)

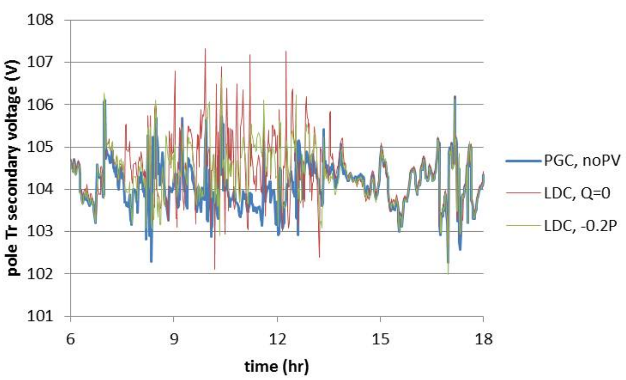

Fig. 8.29 Voltage deviation by PV's fast output change (LDC)

Voltage simulation results using measured output fluctuation data of existing PV (without considering smoothing effect) are shown in Fig. 8.29 (PGC) and Fig. 8.30 (LDC). Larger voltage fluctuation is seen in case of PV integration than no PV case. Especially voltage fluctuation is large during 10 to 13 O'clock. In case that PV's constant leading power factor operation is not used (Q = 0), voltage often exceeds 107V for a short time. In case that PV's constant leading power factor operation is used (Q = -0.2P), fast fluctuation is suppressed.

Voltage calculation results in the five cases are summarized in Fig. 8.31. Since permitted voltage range is assumed 101 to 107V at pole transformer secondary, its center voltage 104V is taken as standard and maximum, minimum values and standard deviation are shown. Comparing to no PV case, in cases that PV integrated and constant leading power factor is not used, maximum increases, minimum deceases, and standard deviation increases both in PGC and LDC. In case that constant leading power factor is used, maximum decreases, minimum increases, and standard deviation decreases than former case both in PGC and LDC, and maximum voltage does not exceed 107V. In these cases, difference between PGC and LDC is small. Thus, PV's constant leading power factor operation is also effective for voltage fluctuation mitigation caused by PV's fast output fluctuation.

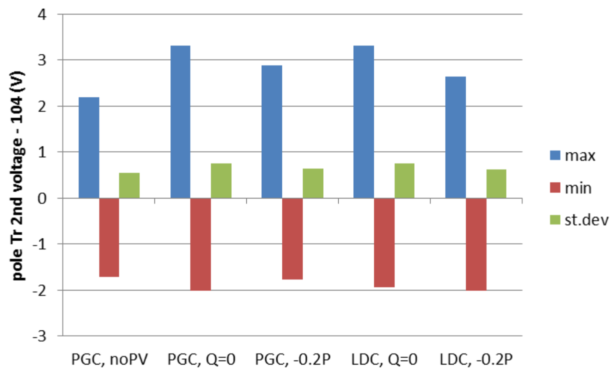

Fig. 8.31 Voltage deviation due to PV's fast deviation (sum)

So long as PV's output change is not so severe, voltage rise by high PV integration seems to be avoided. However, it must be noticed that study above assumes that PV distributes evenly in residences. Certainly very severe PV output fluctuation and uneven PV distribution are remained subjects PV, it is certain that PV's constant leading power factor operation is a promising mitigation method for voltage deviation.

Impact of PV's constant leading power factor operation to trunk system(6)

Impact of leading power factor to trunk system is assessed. For conservative, voltage support effect by outer system is neglected. At each load system a group of capacitors locate at secondary bus of interconnection substation, and are switched on/off to maintain primary side voltage. Interconnection transformer (black in figures) and distribution transformer (gray in figures) have LTC (on-Load Tap Changer), which is controlled to maintain secondary voltage. Certainly EHV (Extra High Voltage) transformer has LTC, but it is controlled by voltage reactive power control (VQC) for system wide control, so it is assumed not operate here. Since to handle detailed system is technically difficult, model is simplified by Y-connection aggregation. Therefore, all paths from power source to load are considered.

Each generator in trunk system is controlled so as to maintain its terminal voltage by AVR (Automatic Voltage Regulation). Each generator in secondary system (66kV class) is controlled so as to maintain its power factor by APFR (Automatic Power Factor Control).

Sum of integrated PV's rated capacity is assumed as 30% of demand. If Japan government's plan is realized, such amount of PV is integrated. It is assumed that each PV increases output power from very low to rated power during short time as 10 min (during 10 min to 20 min). Loads' voltage rise, capacitors are switched off, LTCs descend their tap position. PV power factor is assumed as three cases: Q = 0, Q = -0.2P, or Q = -0.4P.

The author calculated on ten trunk systems in Japan. Major difference was not seen. Those ten systems seems to be classified to four groups, so one typical example of each group is introduced.

Example system C Its structure is shown in Fig. 8.32. It consists of 20 generators and 17 loads, and interconnects to outer system via one tie line.

Time variation of total PV reactive power (QPV), total generator reactive power(QG), and total capacitor reactive power (QC) are shown in Fig. 8.33. QG decrease is scarcely, and QC decrease is considerably mitigated by PV's leading power factor increases.

Time variation of load voltage (VL), interconnection transformer tap (TT), and distribution transformer tap (TD) are shown in Fig. 8.34. VL is well maintained by capacitor switch off and tap position decrease. TT decrease is slightly, TD decrease is a little better mitigated by PV's leading power factor.

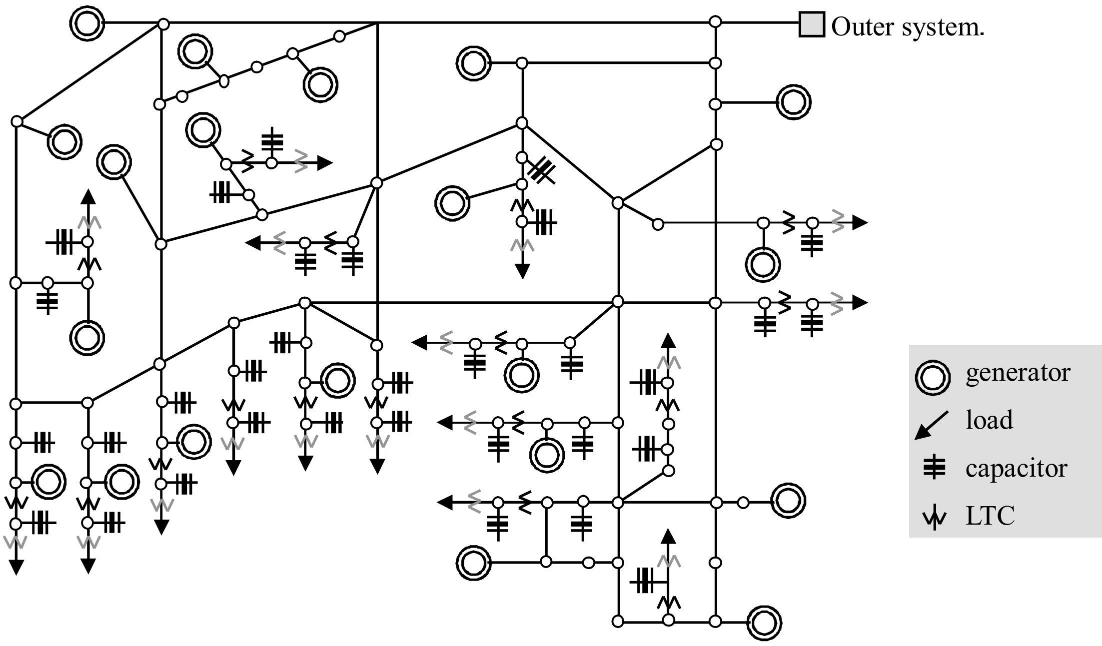

Fig. 8.32 Structure of example system C

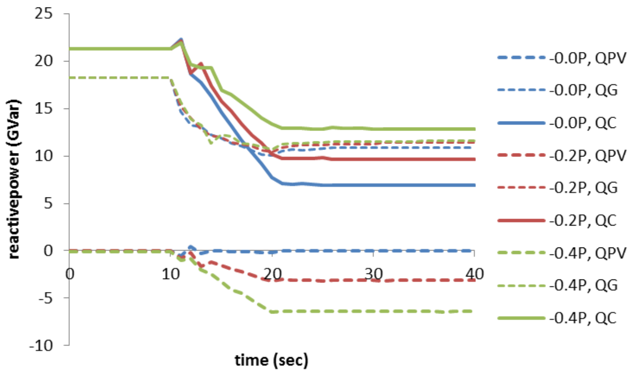

Fig. 8.33 Time variation of reactive power (system C)

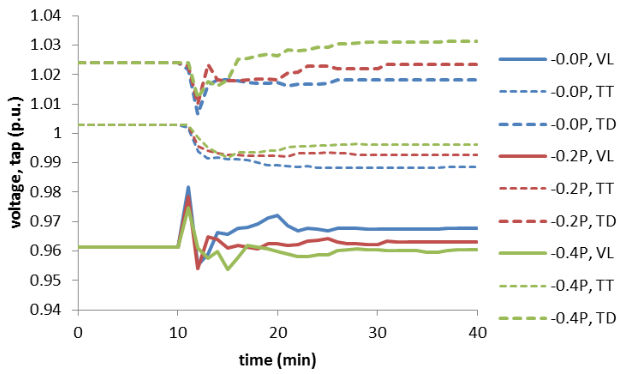

Fig. 8.34 Time variation of voltage and tap (system C)

Example system E Structure of the system is shown in Fig. 8.35. The system has 20 generators and 20 loads, and interconnects via two tie line.

Time variation of total PV reactive power (QPV), total generator reactive power(QG), and total capacitor reactive power (QC) are shown in Fig. 8.36. QG decrease is scarcely, and QC decrease is considerably mitigated by PV's leading power factor increases.

Time variation of load voltage (VL), interconnection transformer tap (TT), and distribution transformer tap (TD) are shown in Fig. 8.37. VL is well maintained by capacitor switch off and tap position decrease. TT decrease is slightly, TD decrease is a little better mitigated by PV's leading power factor.

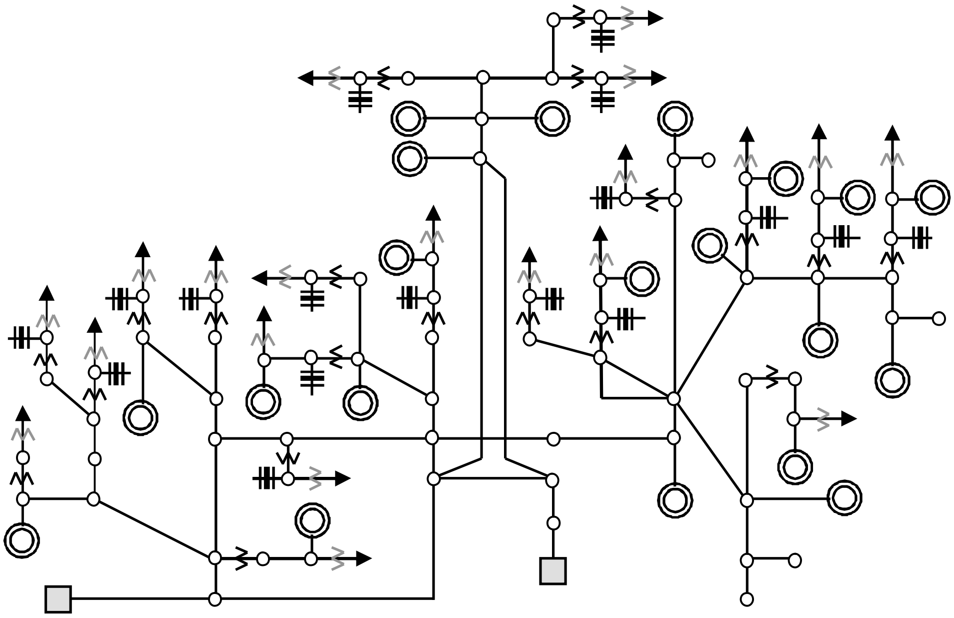

Fig. 8.35 Structure of example system E

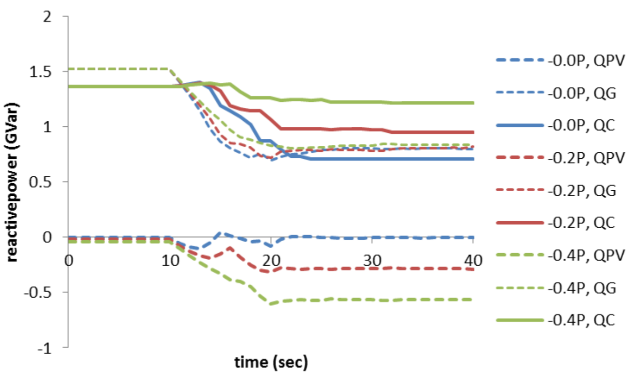

Fig. 8.35 Time variation of reactive power (system E)

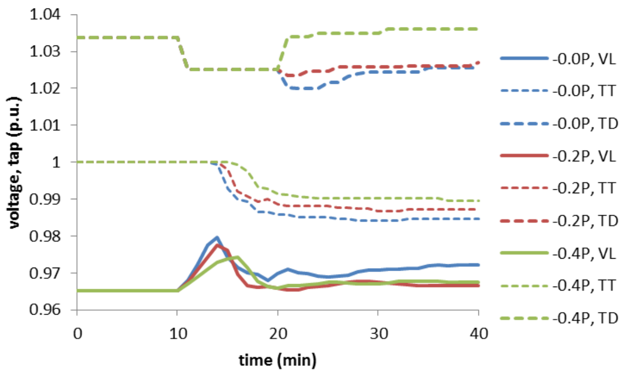

Fig. 8.36 Time variation of voltage and tap (system E)

Example system H Structure of the system is shown in Fig. 8.37. The system has 11 generators and 8 loads, and interconnects via one tie line.

Time variation of total PV reactive power (QPV), total generator reactive power(QG), and total capacitor reactive power (QC) are shown in Fig. 8.38. QG decrease is considerably, and QC decrease is a little better mitigated by PV's leading power factor increases.

Time variation of load voltage (VL), interconnection transformer tap (TT), and distribution transformer tap (TD) are shown in Fig. 8.39. VL is well maintained by capacitor switch off and tap position decrease. TT decrease is certainly, TD decrease is also certainly mitigated by PV's leading power factor, but slight hunting is seen in Q = -0.4P case.

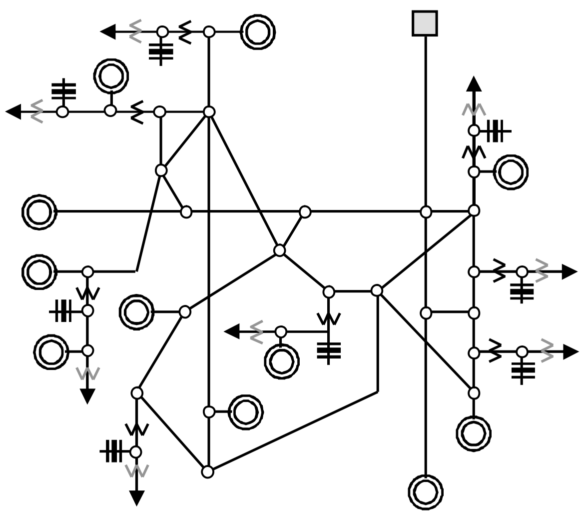

Fig. 8.37 Structure of example system H

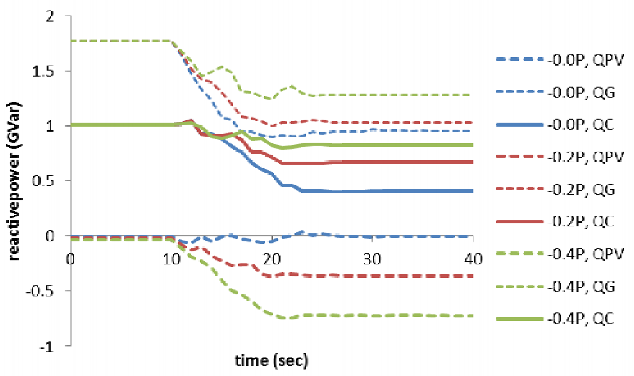

Fig. 8.38 Time variation of reactive power (system H)

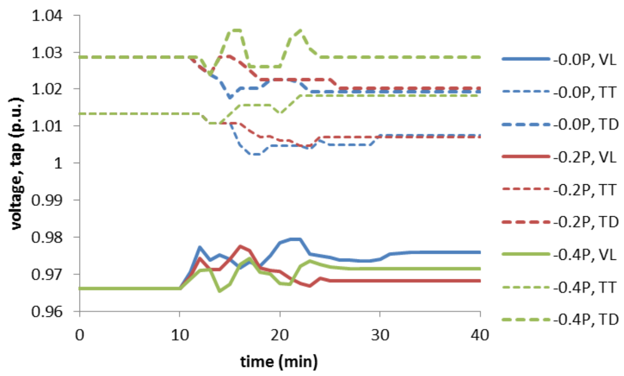

Fig. 8.39 Time variation of voltage and tap (system H)

Example system J Structure of the system is shown in Fig. 8.40. The system has 6 generators and 10 loads, and does not interconnect.

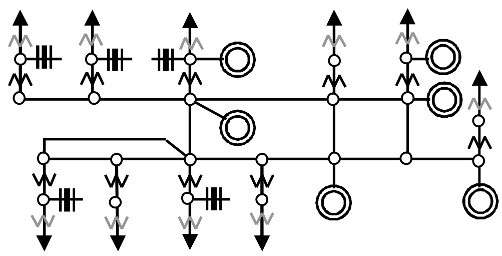

Fig. 8.40 Structure of example system J

Time variation of total PV reactive power (QPV), total generator reactive power(QG), and total capacitor reactive power (QC) are shown in Fig. 8.41. QG decrease is considerably, and QC decrease is a little less mitigated by PV's leading power factor increases.

Time variation of load voltage (VL), interconnection transformer tap (TT), and distribution transformer tap (TD) are shown in Fig. 8.42. VL is well maintained by capacitor switch off and tap position decrease. TT decrease is certainly, TD decrease is also certainly mitigated by PV's leading power factor.

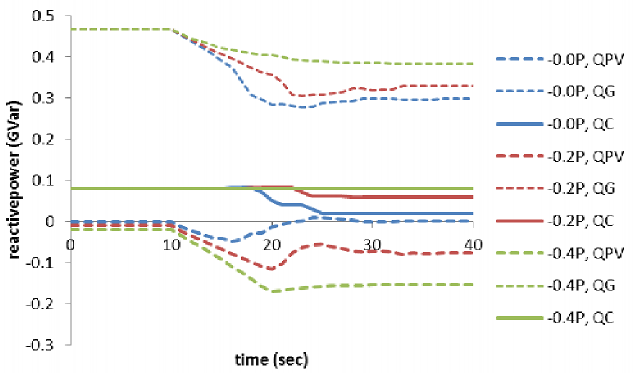

Fig. 8.41 Time variation of reactive power (system J)

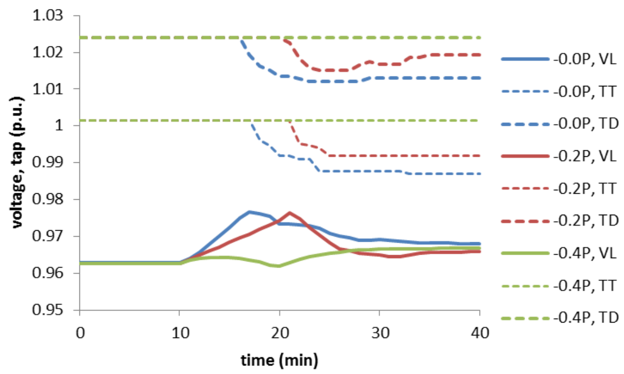

Fig. 8.42 Time variation of voltage and tap (system J)

Equivalent reactance Xeq Analyzed ten systems show common tendencies to PV's leading power factor.

First, decrease of generator reactive power QG scarcely depends on PV power factor as shown in Fig. 8.43. However in system G, H, and J, QG decrease is mitigated by PV's leading power factor. The author thought that the difference depends on capacitor amount per demand. Calculated result is shown in Fig.

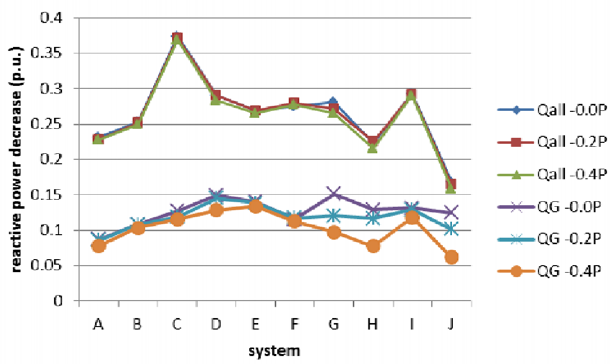

Fig. 8.43 Reactive power decrease by PV power factor

8.44. In system G, H, and J, capacitor amount per demand is small, and QG decrease when PV power factor changes Q = 0 to -0.4P is large. Since there is considerable correlation (R^2 = 0.7916), the explanation is reliable.

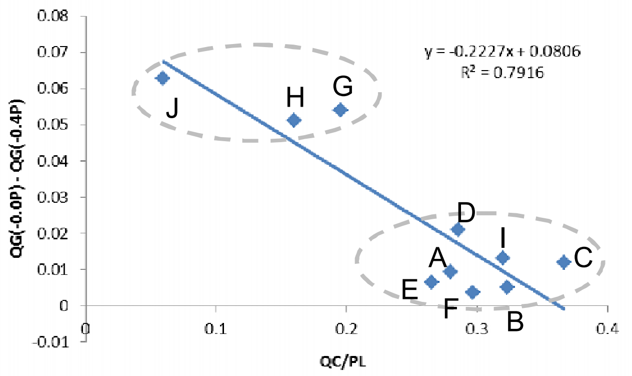

Fig. 8.44 Generator reactive power decrease by capacitor amount

Second, decrease of system total reactive power Qall scarcely depend on PV power factor in the ten systems. The fact tells that major reason of Qall decrease is decrease of reactive power loss in reactance of network. Therefore, let us think of calculating the reactance. Assuming total load (PL) is maintained constant, total reactive loss (Q0) when PV operates at low output (PPV0) and total reactive loss (Q1) when PV operates at rated output (PPV2) are calculated as follows.

$$Q_0 = X (P_L - P_{PV0})^2 \qquad Q_1 = X (P_L - P_{PV1})^2$$

Making difference of them, reactance X is obtained. As follows.

$$X = \frac{Q1 - Q0}{(P_L - P_{PV1})^2 - (P_L - P_{PV0})2}$$

However, the expression is not favorable in comparison between the ten systems. Therefore, per unit method at total load amount is employed as follows.

$$Xeq = X\, P_L = \frac{\dfrac{Q_1}{P_L} - \dfrac{Q_0}{P_L}}{(1 - \dfrac{P_{PV1}}{P_L})^2 - (1 - \dfrac{P_{PV0}}{P_L})^2}$$

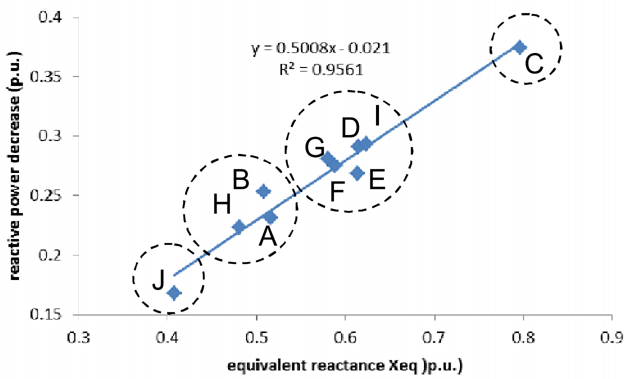

Fig. 8.45 Reactive power decrease by equivalent reactance

Here, Xeq is called as equivalent reactance. An explanation is attempted to explain reactive power decrease by Xeq as shown in Fig. 8.45. The result shows strong correlation (R^2 = 0.9561). This is a matter of course because of Xeq definition. Ten systems are classified to four groups. System C having the largest Xeq shows the largest reactive power decrease. On he contrary, system J having the smallest Xeq shows the smallest reactive power decrease. System D, E, F, G, and I make the second group, and system A, B, and H make the third group. This is the four group that were mentioned at the beginning of the section.

Well, what is the major factor that decides Xeq value? Xeq means reactance from total power source to total load, and it can be thought as an index of power source remoteness. Therefore, when many generators connect

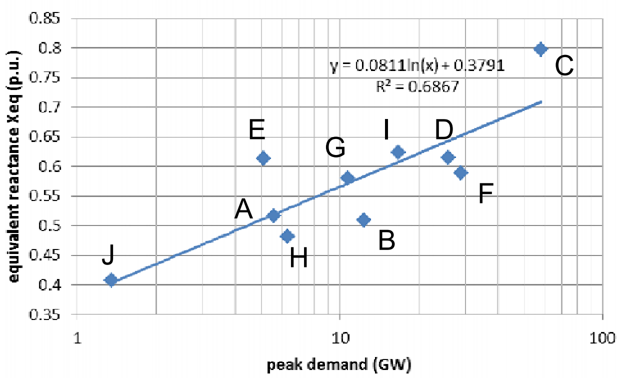

Fig. 8.46 Xeq by system scale

to higher voltage such as 500kV, and when many generators site remote from demand center, Xeq will be large. Such a power system will be a gigantic power system. Therefore, relationship of logarithm of peak demand and Xeq is examined. The result is shown in Fig. 8.46. There is not strong correlation (R^2 = 0.6867), but is clear positive correlation, and the deduction above is reasonable.

As reactive power change in generator is performed only in electric circuit, any hard use does not result maintenance. On the contrary, as switching of capacitor is performed by breaker, frequent use results maintenance. It is laborious to plan maintenance outage without reducing system wide reliability. Therefore, such systems where PV output increase results only small capacitor switching off as system A, H, and J are said to be well designed power system.

Evaluation of PV's constant leading power factor operation Variation of switched off capacitor amount ΔQ_C in the ten example systems is summarized as Fig. 8.47. As the switched off amount is expressed by per unit method at total demand, influence of system scale is excluded. At one glance, ΔQ_C of system C is large and ΔQ_C of system J is small. However, slope of ΔQ_C by PV's Q/P ratio is not much different between the ten systems. Therefore, it can be said that PV's leading power factor operation brings positive effect to all ten systems from viewpoint that capacitor reduce switched off capacitor amount due to PV output increase is reduced.

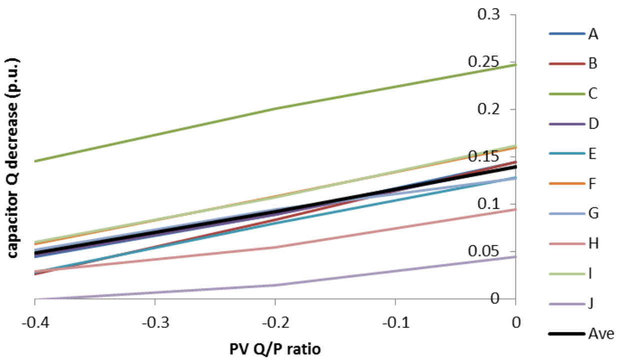

Fig. 8.47 Capacitor switch off by PV's Q/P ratio

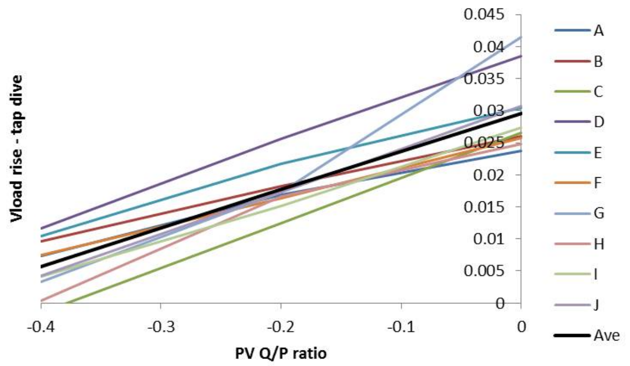

Fig. 8.48 Voltage and tap change by PV's Q/P ratio

As a variable expressing change of load voltage and tap position totally as follows. Here ΔV_L is increase of load voltage, ΔT_T and ΔT_D are tap position decrease of interconnecting and distribution transformers.

$$I_{VT} = \Delta V_L - \Delta T_T - \Delta T_D$$

By PV output increase, load voltage rises and tap position descends. So, subtracting the latter from the former, variation of load voltage and tap position can be totally assessed. The variables of the ten systems are shown in Fig. 8.48 as functions of PV's Q/P ratio. In all systems PV's leading power factor results I_{VT} value decrease and its slope is not different by system. Therefore, it can be said that PV's leading power factor operation brings positive effect to all ten systems from viewpoint that change of load voltage and tap position due to PV output increase is reduced.

Summarizing above, Q = -0.4P or lighter PV's leading power factor operation is favorable to trunk system, and no reason denying it are seen. Even a little heavier leading power factor Q = -0.4P is not regarded harmful for trunk system, by considering total tap operation. However, it must remember that heavier leading power factor brings slightly spoils economy by capacity increase in power conditioner. The author thinks that light leading power factor such as Q = -0.2P introduced in the beginning of the chapter is the best choice.

Importance of PV's constant leading power factor operation in high PV integration

In the early stage of PV penetration, problem was that many PVs concentrate under a pole transformer. Such problem was solved by method that pole transformers are equipped on every pole and low voltage wire is not used. Since resistance is larger than reactance in low voltage system, effect of PV's constant leading power factor was not significant, and therefore, was not noticed.

However, high PV integration became realistic, condition changed. Resistance in MV wire is only around 1/2 of its reactance. Therefore, PV's constant leading power factor shows great effect on mitigating voltage slope in distribution system including distribution transformer.

However, "recommendation of PV's constant leading power factor operation" by the author faced to obstruction. In start of a state's project, the author insisted that "if PV's constant leading power factor operation is not dealt in the project, our utility do not join". As the result, PV's constant leading power factor operation became noticed more effective and economical than the other methods.

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