A Novel Control Approach for Microgrids Islanded Operation - Load Step Pre-announcement and Bang-Bang Control

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Abstract: In terms of high penetration of distributed energy resources, power systems undergo challenges on aspects of their operation, stability and control issues. Microgrids gained a lot of research interest because they have a promising future to integrate the distributed energy resources into the power systems, reduce greenhouse gas emissions and increase the reliability and security of the power systems. Frequency control is an important control method applied in power systems. In this paper, an islanded microgrid implementing frequency control is modeled. Furthermore, a novel control method including load step pre-announcement and bang-bang control is used together with frequency control and some dynamic simulation results of the islanded microgrid are presented. It compares the results among systems with different starting time constants, control schemes and shares of photovoltaics. It also analyzes whether the implementation of load step pre-announcement and bang-bang controller is feasible and useful.

Keywords: Islanded microgrid simulation, distributed generation, frequency control, load step pre-announcement, bang-bang control

1 Introduction

The Microgrid (MG) concept has been proposed due to the high penetration of distributed energy resources (DER) in electrical network systems. Diverse MG projects [1] are carried out globally focusing on their different technology aspects. To ensure a more reliable and secure energy supply system, different control strategies of MGs are researched.

MGs can be operated both in grid-connected and islanded mode. During the grid-connected operating mode, frequency is controlled by the main grid. However, frequency has to be controlled via coordination among distributed generators (DG) within MGs when the latter are in islanded mode. Unlike large conventional power plants, DERs mostly have low or no inertia [2]. Therefore, when a mismatch between power supply and demand occurs in islanded mode, frequency changes quickly and is difficult to be controlled.

In this paper, frequency control is implemented in an islanded MG. In addition, load pre-announcement (LSP) together with a bang-bang controller (BB controller), which intend to improve the frequency response of islanded MGs, are presented.

2 Frequency Control

In islanded mode, any small change in supplied and demanded power of Microgrids can cause a severe frequency deviation because of the small total size of the system. Hence control of MGs is one of the main concerns for MGs operation.

Frequency control [3] is one important control method to maintain the frequency within the nominal operating conditions. In a large power system, frequency control loops, including primary control, secondary control, tertiary and emergency control, are usually available. Among the four control forms, the primary and secondary control are two basic control loops in a power system.

2.1 Primary Control

The primary control of generators provides a local droop control [3] and responds to the frequency deviation of power system within a few seconds. The active power and frequency (P/f) droop control characteristic is formulated as:

$$(f - f_0) = -\frac{1}{k} \times (P - P_{0i}) \qquad (1)$$

The f_0 is the nominal set points of frequency and P_{0i} is the dispatched power of generator *i* defined at the nominal frequency. 1/k is the frequency droop control setting, which is the ratio of frequency deviation to the change of generator power output. Droop settings are usually described as % droop. For instance, when k = 25, it indicates a 4% frequency droop, which means that 4% frequency deviation causes 100% change in power output. With a 4% droop, the power output will increase by 25% if the frequency drops by 1%.

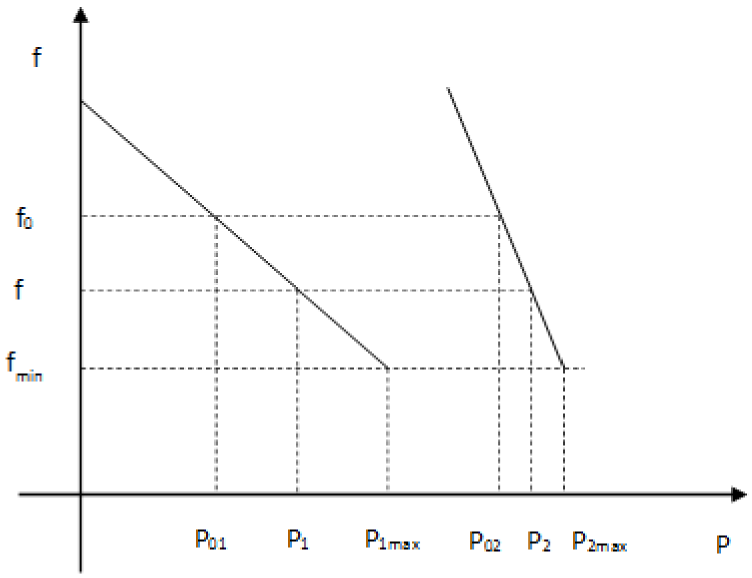

Figure 1. Active power / frequency droop control characteristic [3]

The P/f droop characteristic is shown in figure 1. When the system frequency drops from f_0 to f_1, generators participating in primary control should increase the power output from P_{01} to P_1 and from P_{02} to P_2. When the lower frequency limit is reached, the generators, which participate in the droop control, reach their maximum power rating, which are P_{1max} and P_{2max} as shown in the figure. The droop characteristic allows different generators to operate at the same frequency with different power outputs, track the load change and bring back the frequency. The system frequency stays at a certain value once a new balance between power supply and demand is achieved. However, this new steady point of frequency could be different from the nominal operating point, because of the proportional action of the generators' droop control.

2.2 Secondary Control

The primary control can react very fast to small frequency deviations in power systems. However, it also allows the power systems to operate at a new set point of frequency, which can be below or above the nominal value, once the balance is established between power supply and demand. Therefore, the secondary control [3] is required to restore the system frequency to the nominal value. The secondary control is a feedback control loop, which reacts on the frequency deviation and is added to primary control loop via a proportional-integral (PI) controller. The secondary control works in a timescale of several minutes to bring the frequency back to the nominal point.

In a severe situation, the tertiary control, emergency control and protection schemes should be considered to re-establish the nominal frequency if the frequency drops quickly to a critical value. Under normal circumstances, tertiary control is used to replace secondary control reserves.

3 Load Step Pre-announcement and Bang-Bang Controller

Microgrids have a low inertia in island mode, thus, frequency control of MGs is difficult to be achieved without the support from the overall network. In this paper, load step pre-announcement and a bang-bang controller are designed and applied to provide a better control system to MGs.

3.1 Load Step Pre-announcement

To anticipate the change between load and generation, LSP is planned for the simulation model. LSP receives signals from the load side and delivers them to the overall system continuously. When LSP gets a load change signal, LSP will delay it for a defined short period and maintains the previous load in the system. Meanwhile, LSP gives a signal within the preset time of the delay period to the bang-bang controller to control the conventional generator in order to start increasing or decreasing power output before the real load change happens. Depending on the system inertia constant and dynamics of the generators participating in primary control, the delay time is set differently. In this system, the delay time for releasing a load change is set to be 40 ms, which can be further optimized.

3.2 Bang-Bang Controller

Bang-bang control [4] is often used in the control of non-linear systems. A BB controller is a feedback controller which switches between two states, on and off. Most common residential thermostats are BB controllers which switch on or off based on whether the ambient temperature reaches a preset threshold. Because of their simplicity and convenience, a BB controller for the conventional generator of the system has been designed. After it receives the signal from LSP, it gives a command to the conventional generator to generate full power, in case the load is about to be increased. Likewise, it gives a command to the conventional generator to start decreasing the power output rapidly when the load is about to be decreased. If no change in load is announced, the BB controller does not take any control action. However, in order to avoid any instability which may occur in microgrids, and not to interfere with the function of the primary and secondary control, this action of the BB controller should only be activated within the delay preset time and within a secure limit, so the advanced power production does not trigger the protection action of the conventional generator and influence the output power of the photovoltaics (PVs). The designed BB controller works as presented in figure 2.

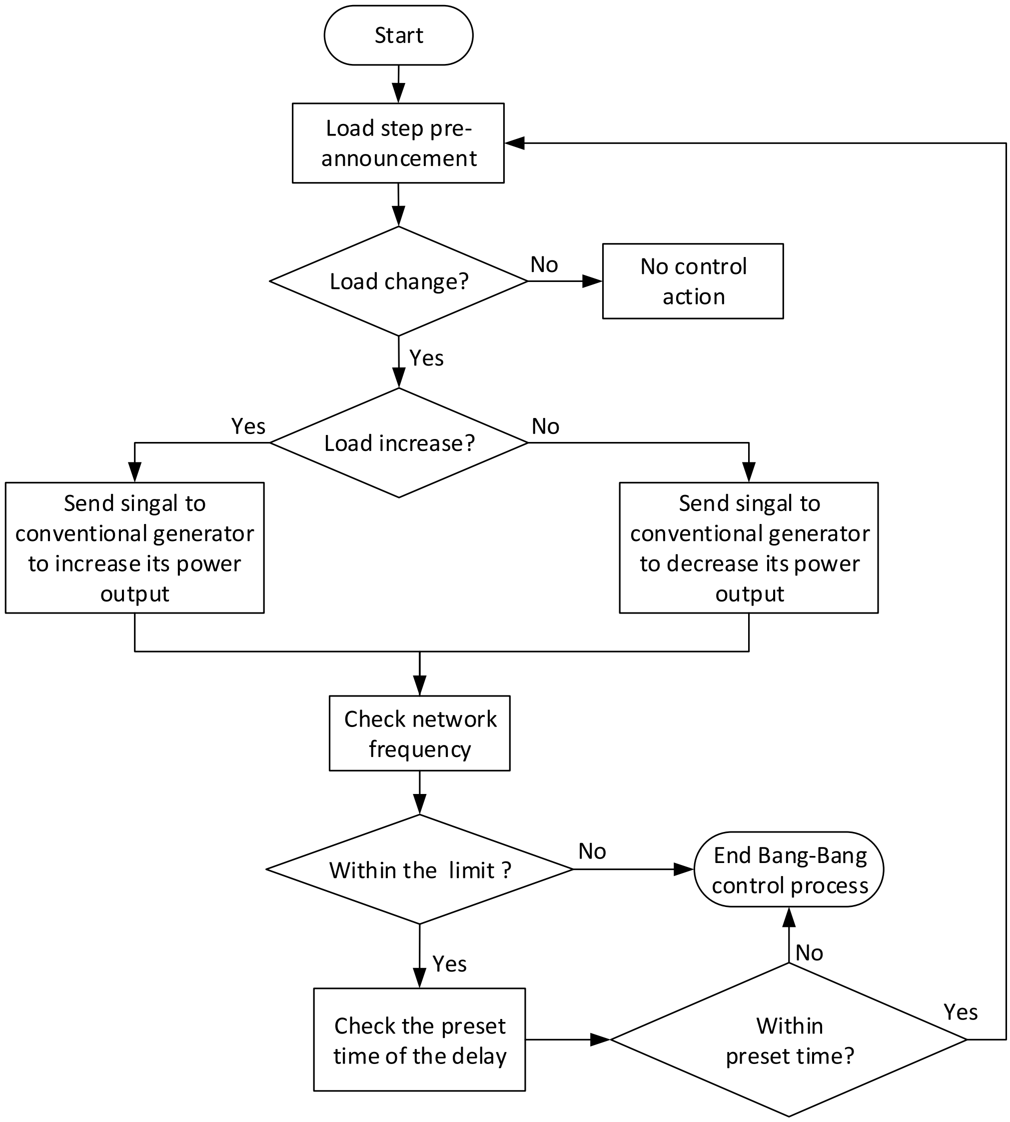

Figure 2. Work process of bang-bang controller

4 Simulation Model

A simulation model of an islanded Microgrid, which consists of a conventional generator, a photovoltaic system and lumped load, is built up in the Matlab Simulink environment. The system is modeled based on the swing differential equation:

$$\sum P_{Generator} - \sum P_{Load} = J \times \omega \times \frac{d\omega}{dt} \qquad (2)$$

where $\sum P_{Generator}$ and $\sum P_{Load}$ are the sum of power output from all generating units and the sum of load consumption in the MG respectively. J[1] is the moment of inertia and ω is the angular speed of the rotor of the conventional generator. The mechanical system starting time constant is defined as:

$$T_A = J \times \frac{\omega_n^2}{P_n} \qquad (3)$$

P_n is the nominal power and ω_n is the synchronous nominal angular speed of the rotor. The nominal angular speed is calculated as:

$$\omega_n = 2 \times \pi \times f_n \qquad (4)$$

where f_n is the nominal frequency. From the equations (2), (3), and (4), the system dynamics of frequency and power deviation between supply and demand (ΔP/f) is formulated as:

$$\frac{df}{dt} = \frac{\sum P_{Generator} - \sum P_{Load}}{P_n} \times \frac{f_n^2}{f_{act} \times T_A} \qquad (5)$$

where f_{act} is the current system frequency. The simulation model is set under per unit (p.u.) base. The schematic block diagram of the islanded MG system is shown in figure 3.

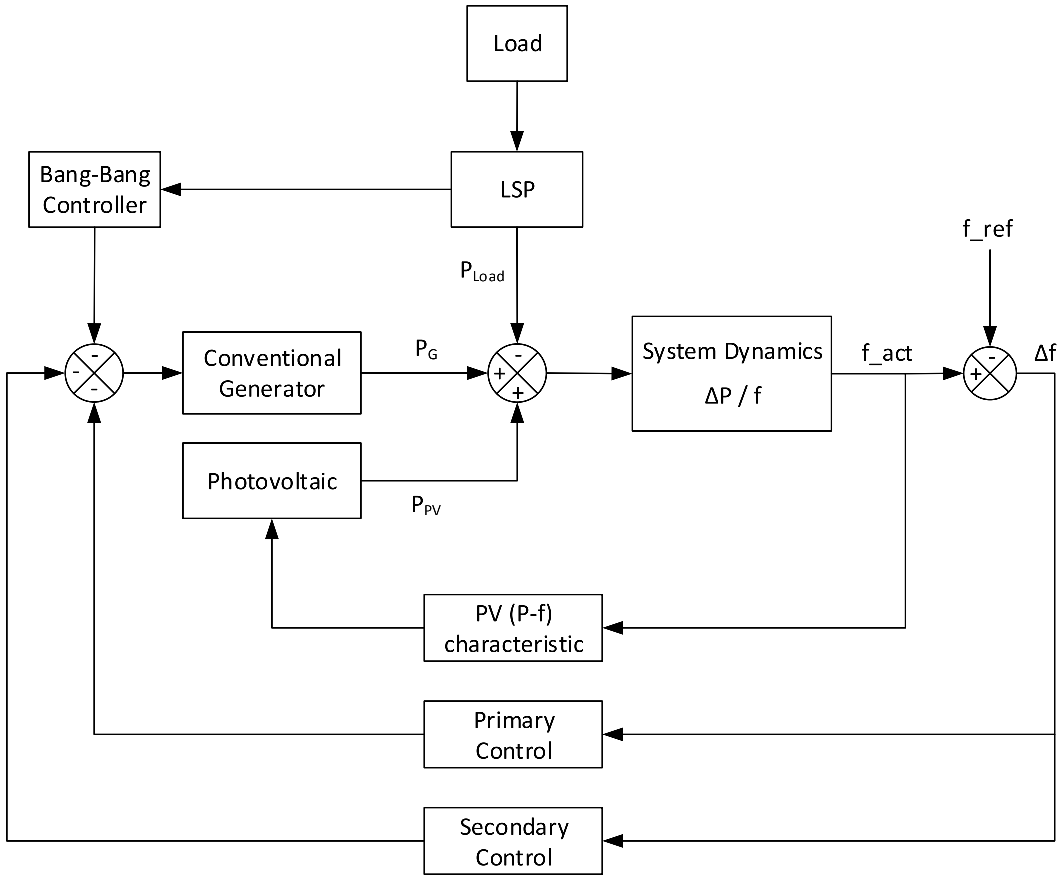

Figure 3. Schematic block diagram of islanded microgrid

[1] For the sake of simplicity, only turbo generators with two poles are considered in the equation. For generators with multiple pole pairs, moment of inertia has to be referred to synchronous system speed.

4.1 Conventional Generator

A conventional generator is modeled in the simulation as stated in figure 4. In order to have a good overview on frequency response of the MG system, a simple first-order lag element is applied for the main control valve motion of the conventional generator. The primary control has a 4% droop setting with a ±0.0004 p.u. (±20 mHz) deadband. Within the deadband, very small frequency deviations should not activate the primary control. When the frequency deviation exceeds the deadband, the primary control responds to the deviation within a few seconds. Load step pre-announcement and the bang-bang controller are added into the feedback loop of the conventional generator model. In the model, LSP and the BB controller are set to take control actions in 40 ms. The secondary control loop uses a proportional-integral controller, in which proportional gain is 1 and integral gain is 0.2. It takes 6 to 7 minutes for the secondary control to bring back the frequency to its nominal value if reserve capacity is sufficient. The parameters of the conventional generator are presented in Table 2 in the appendix.

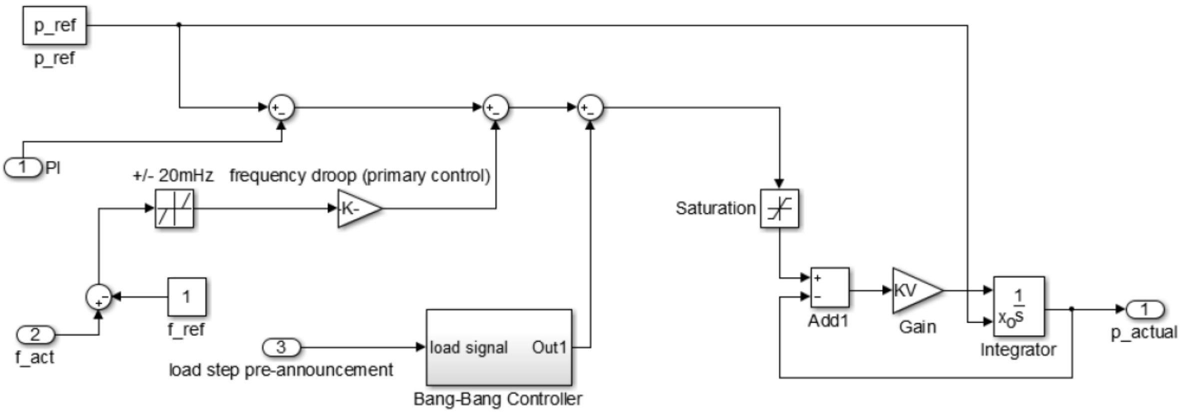

Figure 4. Conventional generator simulation model

4.2 Photovoltaic generator

Photovoltaic generation, which is one of the most important renewable energy sources apart from wind and hydro, is widely used to provide power supply. Besides its environmental advantage, integration of a large amount of distributed generation into power systems causes some technical problems, for example, reversing power flow in the distribution network, additional power flow in transmission level and grid instability issues [5]. Regarding the stability of the grid, German VDE-AR-N 4105 application standard [5, 6] for medium and low voltage networks provides guidance for PVs to respond smoothly to frequency deviations when the system frequency exceeds certain limits.

The frequency characteristic of PVs is presented in figure 5. According to the VDE-AR-N 4105 guide, the PV characteristic of frequency-dependent active power infeed is as follows:

- When frequency is between 47.5 Hz and 50.2 Hz, PVs feed 100% of their actual power output into the network.
- When system frequency is between 50.2 Hz and 51.5 Hz, the power infeed of PVs is reduced by 40% per 1 Hz.
- PVs should be disconnected when frequency is below 47.5 Hz or above 51.5 Hz.

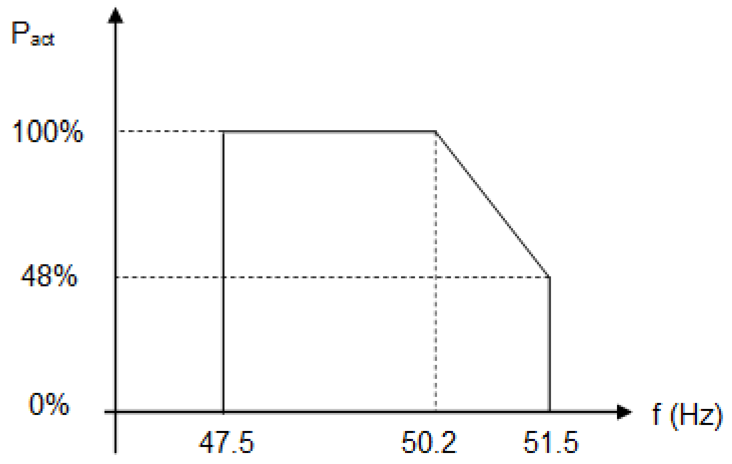

Figure 5. PV frequency-dependent active power infeed characteristic curve [Source: VDE-AR-N 4105]

In this simulation, the PV characteristic curve of frequency and active power from VDE-AR-N 4105 guide is implemented. Furthermore, PVs are allowed to reconnect to the overall system when frequency stays between 47.5 Hz and 50.05 Hz for more than 60 s as described in [5]. In addition, PVs feed 10% of their maximum active power per minute into the system after the reconnection and the maximum active power can be reached after 10 minutes. This avoids repeated disconnection of PVs caused by a fast change in frequency. In order to see the dynamic behavior of PVs, it takes 60 s for PVs to fully provide active power in the model. The PV simulation model is shown in figure 6. The parameters of the PV model are presented in Table 3 in the appendix.

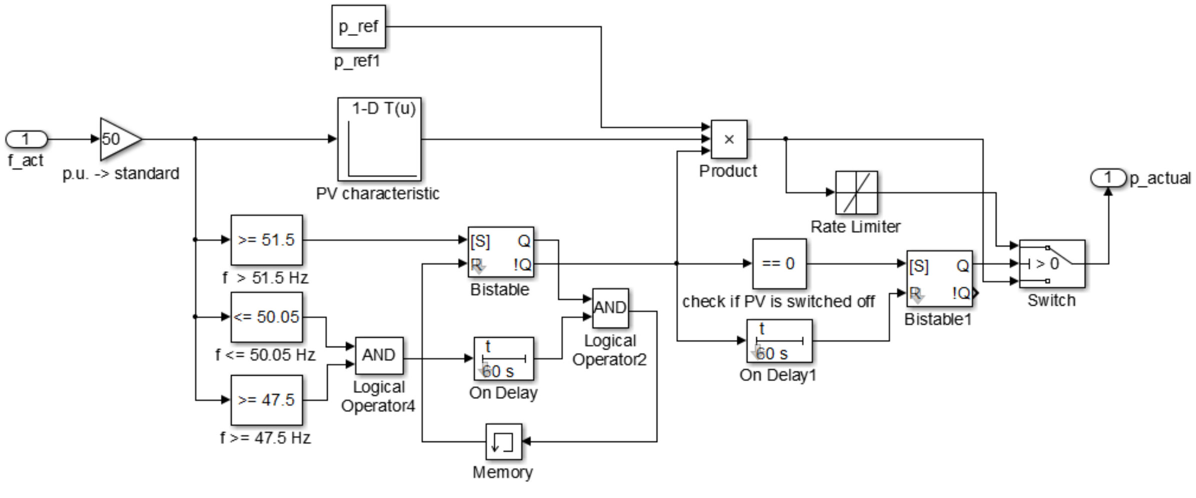

Figure 6. PV generation simulation model

4.3 Load

In the simulation, load change is presented by a step signal. The step signal is connected with LSP. When the load does not make any change, LSP sends continuous load signals to the system. When a load change is noticed by LSP, it delays the change of the signal and maintains the previous state of the system. After the delay time period, the real load change will be sent by LSP to the system.

5 Simulation Results

Simulation results are collected to evaluate the performance of the islanded microgrid system with different control schemes, including frequency control, load step pre-announcement and bang-bang controller. In the model, the initial value of load is set to be 0.5 p.u. and the power set points of the conventional generator and PV are both at 0.5 p.u.

5.1 Dynamic Behavior

In the first simulation, the frequency response of the islanded MG is observed. The load steps down from 0.5 p.u. to 0.1 p.u. at 100 s which has been delayed for 40 ms by LSP. The system is modeled with 0.6 s starting time constant T_A and a 12.5% share of PVs. The simulation results are presented in figure 7.

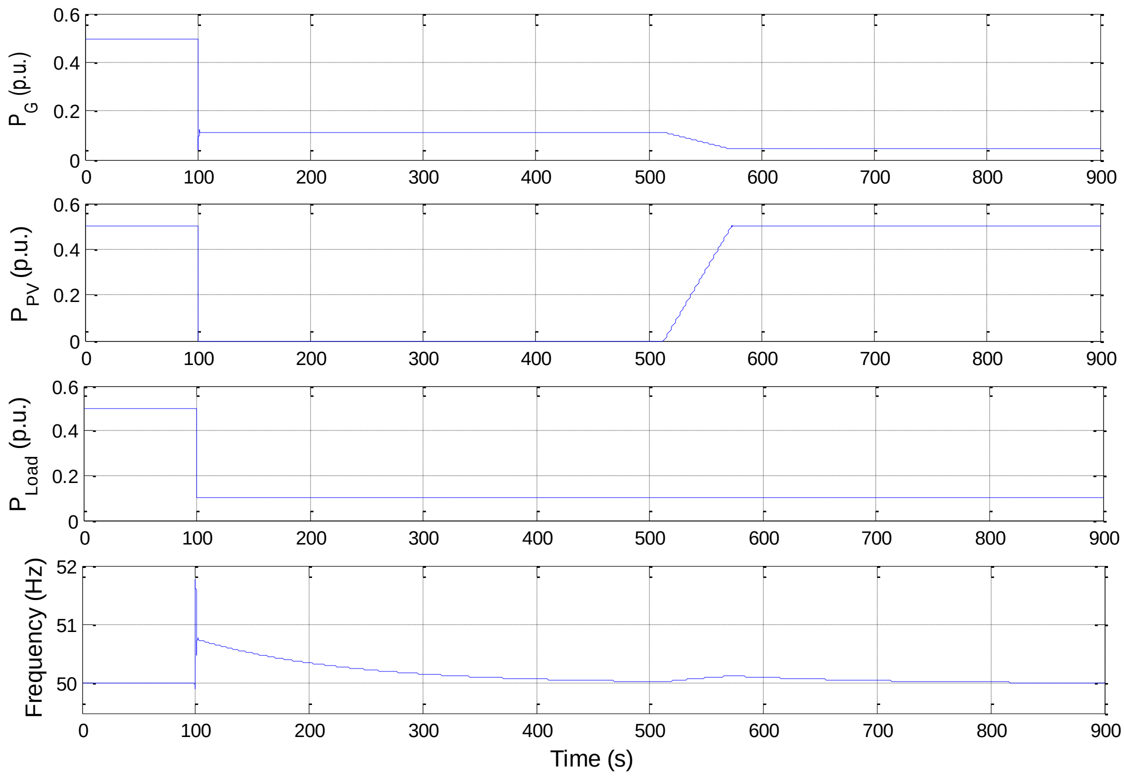

Figure 7. Dynamic simulation results (P_G: the power output of the conventional generator; P_{PV}: the power output of the PV; P_{load}: the power consumption of the load; Frequency: the system frequency)

As it can be seen in the picture, both the conventional generator and PV system react to the frequency change and contribute to stabilize and restore the nominal frequency. When the load decreases from 0.5 p.u. to 0.1 p.u. at 100 s, the frequency increases rapidly. The primary control of the conventional generator reacts in approximately 2 s, afterwards the secondary control starts to recover the frequency slowly. The PV system disconnects from the network shortly after the step change at 100 s when the frequency exceeds 51.5 Hz. The frequency condition for PV reconnection is fulfilled at 455 s, when the frequency is brought to 50.05 Hz by the secondary control. The system frequency is stable between 47.5 Hz and 50.05 Hz for 60 s, so at 515 s the PV generation starts to reconnect to the overall system and then feeds in its power step by step in one minute. The PV feeds 100% of its actual power output into the overall system at 575 s. The reconnection of the PV system causes slight frequency deviation and the primary and secondary control of the system finally brings the frequency back to nominal value at approximately 820 s.

5.2 Results Comparison

In order to find out the impact of LSP and the BB controller on the system, a comparison of the simulation results with different control schemes is made as shown in figure 8. The load step increases from 0.5 p.u. to 0.65 p.u. at 100 s and the share of PVs is 25%. The blue solid line and brown dash-dotted line indicate the frequency response in the islanded MGs having T_A = 0.6 s with LSP and the BB controller and T_A = 0.6 s without LSP and the BB controller respectively.

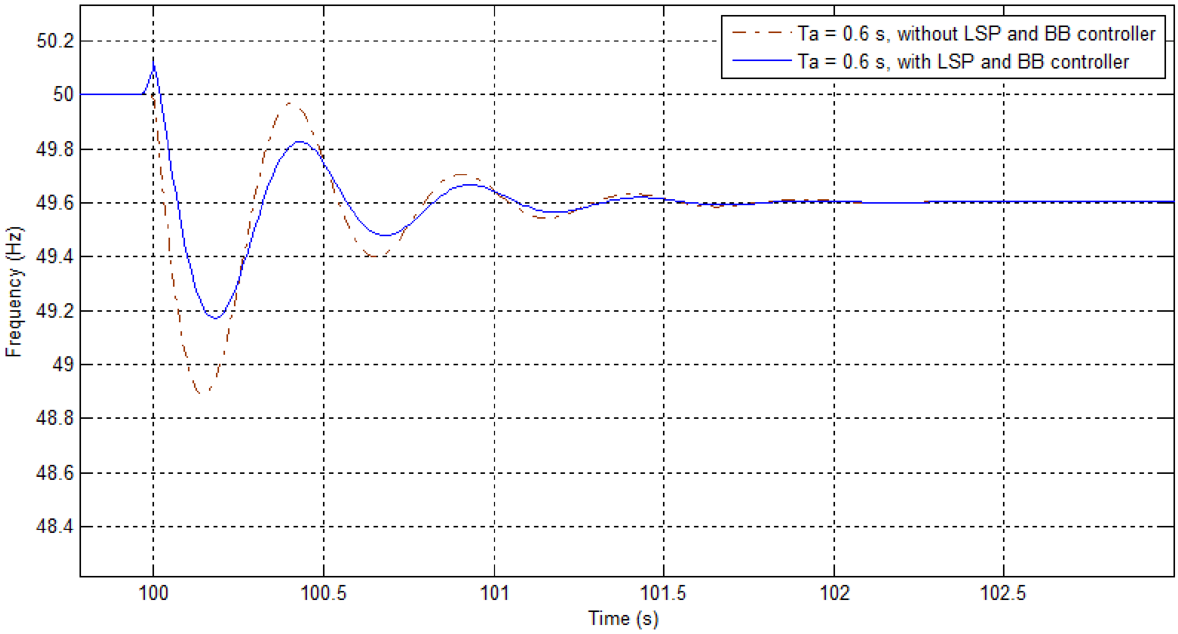

Figure 8. Results comparison of systems with different control schemes

The conventional generator starts to generate additional power at 99.96 s before the load change due to the implementation of LSP and the BB controller. In figure 8, corresponding to the increased power of the conventional generator, the frequency increases and reaches approximately 50.1 Hz. When the load change happens at 100 s, the frequency sags by approximately 0.3 Hz less than the frequency of the system without LSP and the BB controller at the first peak value. By applying LSP and the BB controller, the system frequency dropping does not exceed 49 Hz. Possible load shedding action in case that frequency falls below 49 Hz is avoided. Therefore, the system with LSP and the BB controller has a better reaction on the power disturbance and lower frequency deviation than the one without LSP and the BB controller. It indicates that the designed LSP and BB controller enhance the performance of the MG control system.

5.3 Results Analysis

Figure 9 presents the allowable positive and negative load step in the systems with different control conditions, starting time constants and shares of PVs. For instance, when T_A is 0.6 s and the share of PVs is 0%, the system without LSP and the BB controller has the maximum positive load step as 0.299 p.u., which means that the load can raise from 0.5 p.u. up to 0.799 p.u. Under the same conditions, if LSP and the BB controller are applied, the allowable positive load step is 0.349 p.u. Because of low control possibility of PVs and no inertia from them, a higher share of PVs decreases the maximum load change.

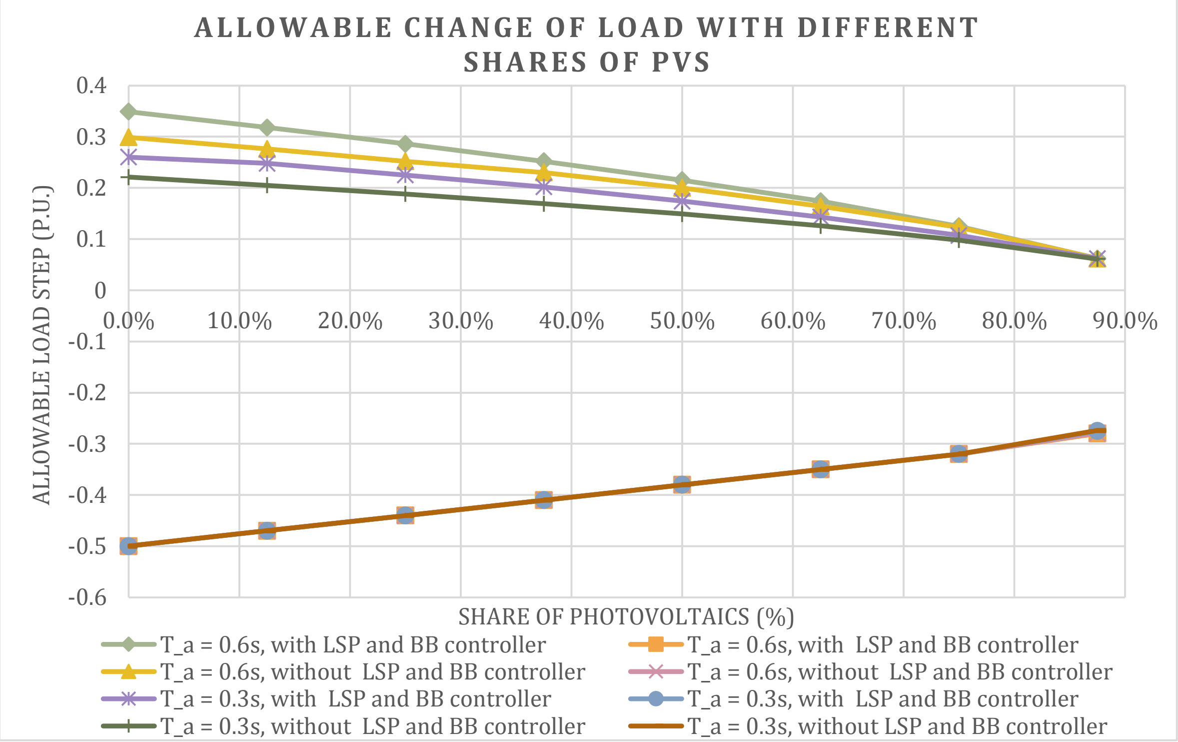

Figure 9. Allowable change of load with different shares of PVs (T_a: system starting time constant)

As shown in figure 9, the implementation of LSP and the BB controller can improve the maximum possible positive load step depending on different shares of PVs based on the same T_A. The influence of LSP and the BB controller on the positive load step reduces when MGs have more power production from PVs, since they are only applied in the conventional generator. Although LSP and the BB controller improve the control ability of the system, they do not influence the amount that the load can be decreased by, no matter how big the system T_A is. This is because if a large load disconnects from the system, the control system brings the frequency to the acceptable range - between 47.5 Hz and 50.05 Hz - for at least 60 s, then PVs reconnect to the overall network. When the reconnection happens, due to the low consumption of load, the low available capacity of conventional generators and the integrated PVs, the frequency goes over 51.5 Hz before the PV system reaches its steady operating point, which triggers the disconnection of PVs. Hence the reconnection of PVs causes frequency oscillation. In this case, the utilization of LSP and the BB controller does not improve the maximum possible negative load step of the system. The allowable decrease of the load depends on the capacity of the conventional generation and the share of PVs in the system. Additionally, the maximum negative load step is generally bigger than the maximum positive load step, since both the conventional generator and PVs can reduce their power output when the load decreases but only the conventional generator can react to the load increase.

Table 1 presents what a percentage of load increase the application of LSP and the BB controller enables. For example, in the system whose T_A is 0.6 s, share of PVs is 0% and LSP and the BB controller are applied, the load can raise 69.8% more than the initial value (from 0.5 p.u. up to 0.849 p.u.). The system without LSP and the BB controller, based on the same conditions of T_A and the share of PVs, is able to increase the load by 59.8%. Thus, applying LSP and the BB controller in the system enlarge the maximum load increase by approximately 16.7%. Due to the fast reaction of the system when T_A is 0.3 s, the system frequency exceeds 50.2 Hz within the preset 40 ms if the share of the conventional generator is high. Hence the power infeed of PVs goes down along the PV characteristic curve. However, this reduction of the PV infeed does not diminish the benefit of the BB controller to the system. As shown in the table, in the system with $T_A = 0.3$ s and LSP and the BB controller, load can be increased by an additional 17.6% more than the one without LSP and the BB controller depending on 0% share of PVs. Therefore, LSP and the BB controller have a greater effect in a $T_A = 0.3$ s system than a $T_A = 0.6$ s system in the 40 ms preset time. It is expected that these results will change in case the preset time is optimized for each incident.

Table 1. The percentage of the load can increase by applying LSP and the BB controller

Share of PVs	Comparison between the systems with and without LSP and the BB controller	
	$T_A = 0.6$ s	$T_A = 0.3$ s
0%	16.7%	17.6%
12.5%	15.2%	20.9%
25%	13.5%	19.6%
37.5%	9.6%	19.5%
50%	7.5%	16.8%
62.5%	6.1%	13.5%
75%	1.6%	9.2%
87.5%	0%	1.6%

6 Conclusion

Load step pre-announcement and bang-bang controller are designed and implemented in the Matlab Simulink environment. According to the simulation results, because of the low control ability of PVs, the load can only change less in systems with a higher share of PVs. Instead of the only reaction from the conventional generator when there is a load increase, both the conventional generator and PVs can reduce their power when the load declines, therefore the maximum possible negative load step is greater than the maximum positive load step. When LSP and the BB controller are applied in the islanded microgrid system, they improve the maximum load increase depending on the share of PVs. However, they do not have any impact on a large negative load step. The allowable load decrease is mainly influenced by the capacity of the conventional generator and the share of PVs.

In conclusion, LSP and the BB controller have a positive effect on the maximum load increase in islanded microgrids. Moreover the BB controller is only activated during the preset delay time of the load change from LSP, which does not affect the other control actions. Additionally they both are simple and easy to be designed, implemented and operated. It is reasonable to add them into MGs during the islanded operation to improve the control ability.

7 Outlook

In order to enhance the performance of the bang-bang controller, the preset time should be further optimized based on different system starting time constants and dynamics of generators participating in primary control. Besides, load step pre-announcement can be developed to be more intelligent, which can decide how long time in advance conventional generators should produce or reduce their power according to the amount of the load change. Since the frequency of the MG system swings after reconnection of the integrated PVs, other control methods for decreasing a large amount of load or a big load loss in MGs should be considered.

Abbreviations

MG	Microgrid
DG	Distributed generation
DER	Distributed energy resource
LSP	Load step pre-announcement
BB controller	Bang-bang controller
PV	Photovoltaic
p.u.	Per unit
f	System frequency
f_0	Nominal set point of frequency
f_1	Changed frequency
f_{min}	Lower frequency limit
P_{0i}	Dispatched power of *ith* generator defined at nominal frequency
P_i	Changed power output of *ith* generator
P_{imax}	The maximum power rating of *ith* generator
$\sum P_{Generator}$	Sum of power output of all generating units
$\sum P_{Load}$	Sum of power consumption of load and losses
J	Intertia moment
ω	Angular speed
P_n	Nominal power
ω_n	Nominal angular speed

T_A, T_a System starting time constant

f_{act}, f_act Current system frequency

f_n Nominal frequency

f_ref Nominal frequency (reference)

Δf Frequency deviation

ΔP Power mismatch between power supply and demand

P_{act} The actual power output of PVs

P_G Power output of the conventional generator

P_{PV} PV power infeed

P_{Load} Power consumption of the load

Appendix

Table 2. Parameters for the conventional generator model

Parameter	Description	Set Value
p_ref	Power set point [p.u.]	0.5
p_actual	Actual power output of conventional generator [p.u.]	Variable
f_ref	Nominal frequency [p.u.]	1
f_act	Actual frequency [p.u.]	Variable
KV	Valve gain	5
Saturation	Maximum/minimum limit of power output [p.u.]	Max: 1; Min: 0
Deadband	Deadband for primary control [p.u.]	± 0.0004
K	Frequency droop (primary control)	25
PI	Proportional-Integral controller	$K_p = 1$; $K_I = 0.2$

Table 3. Parameters for the PV model

Parameter	Description	Set Value
p_ref	Power set point [p.u.]	0.5
p_actual	Actual power output of photovoltaic [p.u.]	Variable
f_act	Actual frequency [p.u.]	Variable
p.u. to standard	Converting frequency from p.u. to Hz	50
PV characteristic	PV active power/frequency characteristic	Look-up table
Rate Limiter	PV stepwise reconnection slope [p.u. / s]	0.0083

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