Abstract—Grid connection of many small-scale renewable energy resources, such as photovoltaics, requires an inverter. This inverter can be controlled in order to detect and thereby avoid islanding, or on the contrary to intentionally island the local electricity grid. The grid owner has no control over an islanded grid, which may be dangerous for repair personnel. Communication should therefore play a role in Distributed Generation (DG) in order to maintain control of an islanded part of the grid. The control method implemented in the 3.3 kW inverter presented here is intentional islanding when the communication is present, and non-islanding when the communication is down.

Index Terms—Inverters, power generation control, photovoltaic power systems

I. INTRODUCTION

Many Distributed Generators (DG) includes a grid-connected inverter. Uninterruptible Power Supply (UPS) also has an inverter as one of the main building blocks. These two devices typically operate complementary: The DG shuts OFF if the electricity grid fails, while the UPS becomes active at the same moment. Combining these two will need only one inverter, thus halving the cost of a combined system. However, the control aims of these two devices are different: The DG output current should be sinusoidal, while the UPS must maintain a sinusoidal voltage. A compromise has been implemented, based on output voltage control [1].

A grid connected inverter feeding power into the grid must detect a grid disconnection event (creating an island) within 2 seconds [2, 3]. This is achieved using a non-islanding control method, also called anti-islanding algorithm. The aim of this algorithm is to try to make the local grid voltage and/or frequency drift out of the tolerance window. This is often done by intentionally make the island frequency or voltage unstable. Positive feedback is here a key concept. Most non-islanding control methods are applied to current control, and the rotating frame (dq0). This paper will present a non-islanding control applied to a voltage-controlled 3-phase inverter in the stationary frame (αβ). Use of the stationary frame is also shown in [1, 4, 5, 6].

In other applications such as microgrids the control is quite different. Here the target is to make the frequency stable, and it is desirable to share the load efficiently among the different generators. In order to do so, negative feedback (droop control) is commonly used [7, 8]. This mode (intentional islanding which is called voltage support in the rest of the text) may be a way of improving voltage quality in the future [9]. To summarize, the inverter in this paper can run in three different modes of operation; UPS (when the grid fails), non-islanding (when the grid is present, but no communication), and voltage support (when both the grid and communication is present, allowing islanding).

From figure 1, it is shown that the only difference between voltage support and non-islanding mode of operation is the sign of the frequency droop. Both voltage support and non-islanding control are well-known technology. By using communication these two self-contradictory control concepts could be combined. Today most DG operates without any communication for control. They basically contain two operating modes: Grid-connected and grid-disconnected. Transitions between these two modes are locally controlled based on measured parameters such as voltage and frequency [2, 3]. If communication is added, informing about the grid status, a third mode could be added; voltage support mode. This mode of operation could intentionally island a part of a distribution grid, compensate reactive power, or do load-shedding. Such functionality alone will however violate the ability to detect an island. Use of communication for islanding detection is shown in [10, 11]. A reliable communication channel will be expensive. Therefore a standard, non-realtime communication such as Internet would be beneficial. This is investigated in [9]. It could be used to enhance control freedom when present, and if the communication falls out the system goes into an operation mode that is degraded but still safe. The different modes of operation are shown in fig. 2. The status of the communication channel decides whether to choose voltage support mode or non-islanding mode. The non-islanding mode of operation is how most DGs are controlled today.

The outline of this paper will be as follows: First the power flow equations will be presented, as the theory background for both grid-connected operating modes. Then a short review of control methods for these two modes will be shown. The
particular implementation of the inverter control method will then be presented. A test bench according to [3] was developed, and an evaluation of the implemented control algorithms is shown.

II. POWER FLOW EQUATIONS

The power flow control is closely connected to the voltage- and frequency control of an eventual island. The power flow calculations are an important part of the islanding control. The inverter is connected to the grid through an LCL-filter as shown in fig. 3. The voltage vectors from the active current $I_p$ and the reactive current $I_q$ seen from the filter capacitor voltage $U_C$ will be as shown in fig. 4.

Connecting two voltage sources together gives the following apparent power (seen from the inverter side):

$$S = U_C \left( \frac{U_C - U_g}{R + jX} \right)$$

(1)

Separating this in active and reactive power gives the following expressions:

$$P = \frac{R \cdot U_C^2 - R \cdot U_{C\text{net}} U_g + X \cdot U_{C\text{net}} \cdot U_g}{R^2 + X^2}$$

(2)

$$Q = \frac{X \cdot U_C^2 - X \cdot U_{C\text{net}} U_g - R \cdot U_{C\text{net}} \cdot U_g}{R^2 + X^2}$$

(3)

Assuming $\delta$ small so that $\sin(\delta) = \delta$ and $\cos(\delta) = 1$, gives the following approximation:

$$P = \left\{ \frac{R \cdot (U_C - U_g) + \delta \cdot X \cdot U_g}{R^2 + X^2} \right\} \cdot U_C$$

$$Q = \left\{ \frac{X \cdot (U_C - U_g) - R \cdot \delta \cdot U_g}{R^2 + X^2} \right\} \cdot U_C$$

(4)

This can be rewritten to

$$P = \left( U_C - U_g \right) \frac{R \cdot U_g}{R^2 + X^2} + \frac{\delta \cdot X \cdot U_C \cdot U_g}{R^2 + X^2}$$

$$Q = \left( U_C - U_g \right) \frac{X \cdot U_g}{R^2 + X^2} - \frac{\delta \cdot R \cdot U_C \cdot U_g}{R^2 + X^2}$$

(5)

Inversely, this is:

$$U_C - U_g = I_p R + I_q X$$

$$\delta = I_p \frac{X}{U_g} - I_q \frac{R}{U_g}$$

Assuming $R \ll X$ makes active power $P$ connected to angle. A leading angle (increasing island frequency) should give more active power to the grid. A higher inverter voltage should give more reactive power to the grid.

A resistance to inductance ratio of 0.158 is assumed in the power controller, of which 1/3 of the resistance is virtual [12]. The 5% virtual resistance is $I_{pf}$ current feedback, which reduces power oscillations. It is assumed to be a part of the
grid impedance. Due to the sum of real and virtual resistive parts of the grid connection, the active power \( P \) will not only be controlled by the phase difference, but also voltage amplitude difference will affect active power \( P \). Similarly, the reactive power will be affected not only by voltage difference, but also by phase difference. The power controllers were improved by taking the resistive part of the grid impedance into account. This is valid when grid-connected. When islanded, the grid resistance will increase under all the test conditions done here. An increase in grid inductance could be done using a rotating machine load instead of the RLC-filter specified in [3], but this was not done during this series of experiments.

### III. VOLTAGE SUPPORT MODE

Voltage- and frequency droops are commonly used for load sharing among different generators [7, 8]. It can be seen from eqn. 5 that commanding more active power will temporarily cause a leading phase, and thus a temporary frequency increase. The steady-state power sharing is communicated through the system frequency. A frequency droop of 1% has been suggested by [8]. The setpoint can be adjusted freely as shown in fig. 1. In non-islanding mode, the setpoint will typically be slightly higher than system frequency in order to make sure all available active power will be fed into the grid. In voltage support mode, one may choose the setpoint to be lower in order to be able to reduce active power if needed.

Equally, a voltage droop governs the reactive power. A voltage droop of 4% has been suggested by [8]. This reactive droop can also be used to stabilize the voltage at the end of a weak grid radial. This will make it harder to detect islanding condition, but it may reduce flicker and improve the line loading. An inverter has a current limit. This means that when it is working at full power, little reactive power should flow through it in order to maximize the active power. In such a situation, reactive power compensation should not be needed, because the active power alone will reduce the line loading. During e.g. cloudy days for a PV system, almost no active power is flowing, so the entire current capacity of the inverter can be used for reactive power compensation. The voltage setpoint could be adjusted by the grid owner.

### IV. NON-ISLANDING MODE

Most non-islanding methods have a voltage and frequency tolerance window as a base. Using only this will leave room for operating points where an island situation will not be detected. There exist methods that try to measure the grid disconnection reflected in phase jumps or changes in harmonics. Others use some kind of positive feedback in order to destabilize either the island’s frequency or voltage. This should lead to a frequency or voltage tolerance violation which means the island is detected.

There exist many non-islanding methods [11]. Some of them are: Slip-Mode frequency Shift (SMS), Active Frequency/Voltage Drift which is similar to Sandia Frequency/Voltage Shift (SFS/SVS). In this paper a pure positive feedback of the frequency deviation from 50 Hz is used. It is connected to the active power regulation through the DC-bank voltage which is controlled by a 5 % droop.

The frequency droop control or its counterpart, the frequency positive feedback in non-islanding control, is implemented with the power controller. The only difference of voltage support contra non-islanding is the sign of the gain. For non-islanding control, a lower frequency than 50 Hz will reduce the output active power \( P \). This will reduce the angle between the grid and the inverter, thus slowing down an island. It will eventually fall below the frequency tolerances. On the other hand in voltage support control, a lower frequency than 50 Hz will increase the output active power \( P \). This will increase the angle between the grid and the inverter, thus speeding up an island and get the frequency close to 50 Hz. In non-islanding mode, the reactive power is controlled to be close to zero, thus no reactive power compensation is used.

### V. STATIONARY FRAME INVERTER CONTROL

A common method of synchronizing a DG to the grid is the use of a phase-locked loop (PLL). The PLL will only track the first harmonic. An alternative method is by use of 50 Hz oscillators running synchronously with the grid [1, 4, 5, 6]. Such a resonance can be modeled using e.g. an LC parallel circuit shown to the right in fig. 5. This can be expressed in unforced state space form:

\[
\dot{x} = Ax
\]

\[
\begin{bmatrix}
\dot{u}_k \\
\dot{i}_g \\
\end{bmatrix} =
\begin{bmatrix}
0 & -1 \\
\frac{1}{L_{g50}} & 0 \\
\end{bmatrix}
\begin{bmatrix}
u_k \\
i_g \\
\end{bmatrix}
\]

(6)

A negligible resistance at 50 Hz can be paralleled with the capacitor, and series connected with the inductor. It will cancel any offset in the oscillation due to initial conditions. In order to synchronize the phase and amplitude of the LC circuit to the grid, feedback with a magnitude \( G \) is used:

\[
\dot{x} = \left(A - G \cdot C\right) \dot{x} + G \cdot y
\]

(7)
It is not necessary to measure the current through $L_{g50}$, but measuring the voltage over $C_{g50}$ is enough to make the system observable. Eqn. 7 expresses a state estimator for the grid voltage. It can be implemented in software by discretizing the continuous time model. The state space matrix $A$ of the continuous time model can be transformed to the $z$-plane state space matrix $A'$ using an indefinite series approximation of the exponential function for a matrix:

$$A' = e^{A'T} = I + \sum_{n=1}^{\infty} \left( A \cdot T \right)^n / n!$$

where $T$ is 100 µs. In order to give a sufficient approximation to the indefinite series, 70 iterations were performed in Matlab. This digital oscillator can easily be included in the state estimator for the LCL-filter shown in fig. 5. The measured 3-phase parameters are the current through $L_{f1}$, the voltage over the filter capacitor $C_f$, and the grid voltage over $C_{g50}$. The state space model for the combined grid and LCL-filter can be modeled as shown in eqn 9:

$$\begin{bmatrix}
    x_g \\
    i_{f1} \\
    i_{f2} \\
    u_f \\
    i_g
\end{bmatrix} =
\begin{bmatrix}
    0 & 1 & -1/C_f & 0 & 0 \\
    -1/L_{f1} & 0 & 0 & 0 \\
    1/L_{f2} & 0 & 0 & -1/L_{f2} & 0 \\
    0 & 0 & 0 & -1/R_{f1} & -1/C_f \\
    0 & 0 & 0 & 1/L_{g50} & -R_{g50}
\end{bmatrix}
\begin{bmatrix}
    x_g \\
    i_{f1} \\
    i_{f2} \\
    u_f \\
    i_g
\end{bmatrix} +
\begin{bmatrix}
    0 \\
    1 \\
    0 \\
    0 \\
    0
\end{bmatrix} u_g$$

An important part of non-islanding control is to adjust the frequency of the reference. This was done by linearizing the discrete $A'$-matrix around nominal frequency. A linearized dependency between natural frequency and the discrete $A'$-matrix was calculated in order to control the reference frequency in real-time. The linearization of the diagonal elements is shown in fig. 6:

$$A_r =
\begin{bmatrix}
    -0.000019736 & -0.00062801 \\
    0.00062801 & -0.000019736
\end{bmatrix}
(f - 50) + A$$

The frequency $f$ is measured using the estimated grid voltage first harmonic. This natural frequency real-time adjustment is done in all grid-connected modes.

VI. EXPERIMENTAL SETUP

A three-phase 3.3 kW inverter test setup was connected to the grid through a test setup as shown in fig. 7 according to [3]. This made it possible to do repeatable tests, in order to document the time to detect islanding condition. The disconnect event was also used for documenting islanding in voltage support mode.

VII. RESULTS

In order to evaluate the effect of the positive feedback in non-islanding mode, test runs were executed. First maximum islanding time was measured, assuming the tolerances are: Frequency: 48..52 Hz. Voltage: 184..276 V. The time to detect islanding is the time until one of these limits is violated. The actual tolerances in the inverter was 45..55 Hz in order to clearly show the frequency positive feedback. The tolerances are wider than what is common for DG, but chosen so wide to not be violated for the voltage support mode. Typical test run results are shown in fig 8 & 9, and a summary of several tests is shown in fig 10.
VIII. DISCUSSION

The non-islanding control is closely connected to the power control of an inverter. In this setup it was necessary to consider these two aspects together as a whole. Some use band pass filtering, which can separate these two control aspects in steady-state situation. It may work well in a current-controlled setting. However, it was not possible to do here probably due to the choice of filter voltage control as the main inverter control objective.

The voltage support control was implemented using droop control. It handled both diode-rectifier load and power imbalance before disconnection of the grid. This mode has reactive power compensation included, which may be beneficial in weak grids where frequent disconnection is also most probable.

The inverter control’s measurement noise level was high. This reduces the time to detect an island. In a less noisy environment, it is reasonable to believe that the time to detect an island will be longer.

Real-time adjustment of the natural frequency of the grid estimator worked as assumed. Working independently of the power controller, it was active both in voltage support and non-islanding mode of operation. Frequency adjustment of the estimated 5th and 7th voltage harmonics was not done. It was not considered relevant because the estimation is only active in non-islanding mode, when the frequency tolerances are relatively tight.

Measuring the voltage over $C_f$ was used in the estimator. It is, however, not necessary in order to make the system observable. See [4] and [5] for a more thorough discussion.

Detection of a cease of communication was used for island
detection. This was possible to do in the lab. Estimation of communication channel time delay was not implemented. Even though the timeout was relatively long (500 ms) compared to what should be possible to do within a restricted geographical area, it puts some requirements on the communication speed. The communication in this setup was done directly point-to-point. This has scaling difficulties. Using flooding is a good algorithm for ensuring the scalability of the system. It will, however, increase time delay of the communication channel.

A grid company, who is going to repair a specific part of the grid, would need to independently turn OFF all DG capacity in a specific area without affecting the other areas. A kind of group-oriented protocol should be used in order to address this functionality.

IX. CONCLUSION

The presented system can run in non-islanding mode, and in voltage support mode, in addition to standalone (UPS) mode. The operating mode transition in case of communication error worked as assumed, making the system gracefully degradable. The non-islanding mode used less than 400 ms to discover an island. In voltage support mode, cease of communication was detected in less than 1.5 seconds. Together this makes it possible to stop an island in less than 2 seconds.

X. FURTHER WORK

Testing with a shorted grid should be done before using this in a commercial product. A solid-state switch would be preferred over the relay currently used for grid disconnection internally in the DG, in order to improve the speed of disconnection. For grid open-circuit failure the relay opening time is not critical and it does not cause power outage to the local critical load due to the voltage control which is used in all modes of operation.

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