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Aggregation of Power grid Models

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Title: Aggregation of Power Grid Models

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Problem Description:

Power grid models have different degrees of aggregation, which is necessary for different purposes. For example, one model can contain only the medium and high voltage parts of the grid while another model of the same grid may include the complete grid, like 66 kV with separate models for even small generators. It may be undesirable either to exclude the low voltage or to use the complete model. Therefore, it is not necessary to maintain many versions of the same model. Instead, we want to have one reference model with a high degree of detail and with the possibility to create more aggregated models on the basis of this reference model. Then the impact of the low voltage grid parts needs to be included in the aggregated model.
The goal of this project is thus to have a tool to develop an aggregated power system models with the appropriate level of details and acceptable errors to be used for selected applications like dynamic studies and control, power flow, market modeling, etc. This is because the aggregated models don't perform as good as the detailed one due to the aggregation of system components. Therefore, the project may include:

– Literature survey on available methods and tools for model reduction and aggregation.
– Demonstrate selected methods and applications by a case study.
– Compare the performance of full and reduced models.
– Develop scripts in Phyton or similar programming to automate part of the aggregation procedure.

The above explanation is a rephrased project description given by Statnett with a recommendation that this project could be done under the cooperation of one student from Power Systems to focus on grid issues and verification and one from Engineering Cybernetics to develop the search algorithms that are necessary to automate the aggregation.

Supervisor: Kjetil Uhlen, professor

Abstract

In recent days, energy demands are growing rapidly. To meet this demand rise, several distributed energy sources and power generations are adding to the existing power system network. At the same time, cross-country and continental interconnections are becoming attractive investments due to a high share of renewable energy sources, mainly wind and solar. This increases the physical size as well as network data of the power system model. Consequently, monitoring and studying such a very large power system model becomes more challenging and complex task. Therefore, it is neither practical nor necessary to use the complete and detailed grid models. As a result, the need for aggregated models has been driven by several reasons in analyzing and monitoring the grid data. Limitation of time, memory and power to run the complete model, and accessibility of network data are some critical reasons. The execution time of such a big power system model may exceed the required time in short-term decisions while studying the stability, system planning, and market analysis.

One practical approach to overcome these problems is, to replace less important parts of the grid by an equivalent model for a specified acceptable tolerance of model aggregation. Depending on the clustering techniques and the intended use of the equivalent model, power grid aggregations are divided into static and dynamic aggregations. Both the available static and dynamic power grid aggregation methods are studied in this report and case studies have been accomplished in a commercial simulation tool called Power System Simulator for Engineering (PSSE) using Python scripts.

In the first case study of this project, an automation based on Python scripts has been developed to aggregate some part of the Norwegian grid model targeting on the low voltage parts of the grid and the static aggregations were performed based on voltage levels. The equivalent parameters of the aggregated models are determined to preserve the steady state results of the generator and load buses in the same voltage ranges. The targeted area containing 82 buses with a base voltage less than 66 kV has been aggregated into four generator bus system. The

equivalent steady state power flow solutions of the aggregated model showed that this methodology can be applied to simplify grid models used for power flow studies and market analysis. Since this method doesn't take into account any dynamics, these aggregated models cannot be used to accurately preserve the dynamics of the system during stability studies. Due to the challenges to fix the parameter configuration problems of user-defined models in such a big case study, the Norwegian grid, a dynamic aggregation has been studied in another smaller power system model.

To emphasize on how to preserve system dynamics, an aggregation methodology based on coherency identification has been applied to IEEE 24 bus test and reliability system. Since coherent groups are made based on their dynamic response this methodology gives better dynamic equivalent models which can be used for stability studies. The coherent groups of a given system differ based on the type, location, severity and duration of the system disturbance under consideration. The coherency level of the machines will also depend on the type of fault initiated during the stability study. This makes the aggregation difficult to form one unique dynamic equivalent model that can be used to maintain the dynamics of each machine in the coherent group. The impact of these scenarios in determining the coherency of machines has been investigated by considering a three-phase bus and a line to ground faults. The dynamic equivalent models of the case study, following these disturbances, are developed together with their network parameters and dynamic simulation results. Most machines respond coherently during the three-phase fault and hence the case study, which originally contained 24 buses, has been aggregated into two generator bus system. Whereas in case of a line fault, the dynamics of the machines differ and the coherent groups are increased resulting in an equivalent model containing six generator buses.

Preface

This thesis report is submitted in partial fulfillment to the completion of my MSc study in Faculty of Information Technology and Electrical Engineering at the Department of Electric Power Engineering, Norwegian University of Science and Technology (NTNU). This thesis was done in coordination with Statnett, a Norwegian state-owned enterprise responsible for owning, operating and constructing the power grid in Norway. The project was carried out from Jun 28 - Dec 30, for 23 weeks excluding Christmas time, in the autumn semester of 2017 and Professor Kjetil Uhlen has been supervising this work. To the best of my knowledge, this report is the original product of my thesis project work except where acknowledgments and references are made.

Mulugeta Hadis Amare

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Acknowledgement

I would like to take this opportunity to acknowledge those who have contributed in different ways while I was doing this thesis and thanks God for having you all.

Firstly, I must sincerely thank my supervisor, Professor Kjetil Uhlen for his continuous guidance, encouragement and incredible patience throughout this project work. I am so grateful to Statnett for the cooperation to work on their grid model data. This work would not have been accomplished without the financial support from the Norwegian government and special thanks for offering me the scholarship to study my master's degree.

I would also like to thank staff members of our faculty Kristoffer Halseth, Halsten Aåstebøl, and Arild Ohren at Office of International Relations for facilitating the administrative support during my study, especially through some of my difficult time. Special thanks go to my classmates Syed Ali Irtaza and Zaw Win Htun for the valuable suggestions in writing my report and all their kindness during all the cooperative works.

I am really grateful to my mother, for always being the source of my happiness and inspiration throughout my life.

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List of Acronyms

AC Alternating Current.

API Application Program Interface.

AVR Automatic Voltage Regulator.

DAE Differential and Algebraic Equations.

DC Direct Current.

DE Dynamic Equivalent.

DER Distributed Energy Sources.

ED Eulidean Distance.

EHV Extremely High Voltage.

EMF Electromotive Force.

EMS Energy Management System.

FACTS Flexible AC Transmission Systems.

GPS Global Positioning System.

GUI Graphical User Interface.

HSV Hankel Singular Values.

HV High Voltage.

IEEE Institute of Electrical and Electronics Engineers.

LTI Linear Time Invariant.

LV Low Voltage.

MSE Mean Square Error.

MV Medium Voltage.

MVA Mega Volt Ampere.

NTNU Norwegian University of Science and Technology.

OPF Optimal Power Flow.

PMU Phasor Measurement Unit.

PSS Power System Stabilizer.

PSSE Power System Simulator for Engineering.

PV Real Power and Voltage magnitude fixed bus.

REI Radial Equivalent Independent.

RR Reduction Ratio.

RTS Reliability Test System.

SCADA Supervisory Control And Data Acquisition.

SSSC Static Synchronous Series Compensator.

SVC Static Var Compensator.

TD Time Domain.

WAMS Wide Area Measurement/Monitoring Sytem.

ZIP constant impedance(Z), current(I), and power(P)) Composite load model.

Chapter 1
Introduction

In a very large power system network served by many utility owners and system grid operators, power system models are the key tools to process data and exchange information among several parties. The summarized results of these models are used as input for system operational studies and future planning explorations and market analysis. For a very large grid models containing different voltage levels, the medium and high voltage parts are the most key study areas. For this reason, it is more logical and computationally inexpensive to replace the detailed low voltage parts of the model with simplified and aggregated models that can decently retain the main information in the complete grid.

In a power system network with a low density of DER, the long-term planning model would include lower voltage levels than the EMS/SCADA model. However, with a high density of DER, like the cross-country interconnection of Nordic and Baltic transmission grid shown in Figure 1.1, only voltage levels above 132 kV, and similarly for a complete Europe continental grid model, there would be a need for more detailed representation of lower voltage level since the need for observability in the lower voltage network is higher. However, it is impractical and computationally expensive to execute the detailed model and this gives the motivation to develop an aggregated or equivalent model. Consequently, the way these DER or low voltage grid networks are represented will affect the stability as well as the aggregated data of the entire power system. As a result of this combined effect, the system parameters and simulation results of these grid parts need to be aggregated into an equivalent network which can be finally combined with the rest of the grid model for a complete power system study. Sometimes, the portion of the grid required to aggregate is referred as external and the remaining part is referred as internal or study subsystems.

Figure 1.1: Transmission grid of Nordic and Baltic regions [a]

[a]**Source:** http://www.nordregio.se

Therefore, it is required to represent each subsystem by an acceptable aggregated model with appropriate system components and network parameters. Dynamic aggregation (equivalencing) is a practical and logical way to reduce the complexity and computation burden of such models while at the same time preserving the dynamics of the detailed model. The required level of aggregation increases with cross-border/country and continental grid interconnections and hence the combined effect of imprecise aggregation will result in less accurate results depending on the intended purpose of the equivalent model. A review of dynamic aggregation methods and the validation of the results are presented in this paper by applying the proposed methodology on part of the Norwegian grid model.

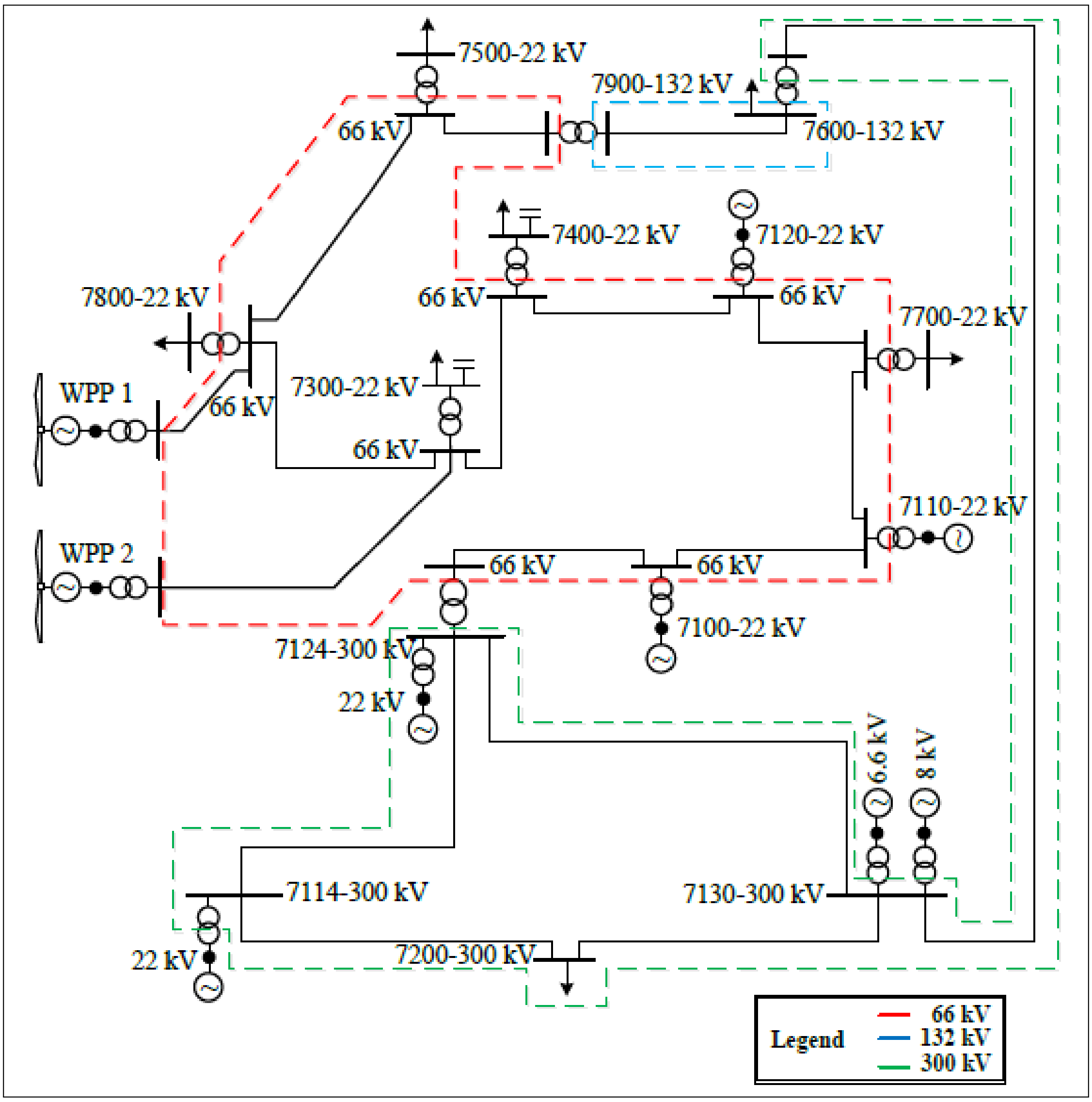


Figure 1.2: The need of power grid aggregation [25]

In a multi-layered enterprise of power system operation and control like in Figure 1.2, the power grid models have different voltage levels and energy sources. In using such models the user needs to choose which voltage levels to focus depending on the intended purpose of the results. However, it is undesirable to run the complete model when it is not required to have detailed results. Instead, it is desired to have the possibility to create more aggregated models on the basis of one reference model with a high degree of detail. Theoretically, this problem can be solved using a flexible dynamic grid aggregation developed to represent a given part of the grid model for a specific scenario. For this reason, it is important to consider the characteristics and interactions of every component in the grid. This makes it difficult to reduce the grid size while at the same time maintaining the dynamics of the system and the complexity increase with the grid size required to aggregate.

1.1 Problem Statement

Due to the rapid growth of cross-country power system interconnections, higher penetration of distributed generation (mainly wind and solar) and comprise of thousands of smart metering devices, the size, and complexity of power system networks is growing at an extraordinary rate. The growth of grid interconnection with Europe continental, a high share of renewables and customer interaction, as a result of the smart grid, are also becoming the main challenges of the Nordic power system. Analyzing power system functionalities and dynamic characteristics based on a detail and complex mathematical models give an accurate system representation. However, for the following summarized reasons, [14] it is neither practical nor necessary to use the detailed models.

- Practically, there is a limitation in computation time, memory and accuracy to perform dynamic simulation and stability analysis using the detailed models. Consequently, it is difficult and expensive to maintain the relevant database for such a large system.
- In cross-country grid connection, the power system belongs to different grid owners and their corresponding control center. Each owner is not interested in the detail system characteristics of others' network data which treats them as external subsystems. This can be also due to the requirement of system owners to disclose their detailed information for business or grid security purpose.
- For power system networks containing a wide geographical area, parts of the system far away from a disturbance have a little impact on the system dynamics. For example; in a power system network with a very large network structure containing several voltage levels a failure and disturbance in the low voltage part has a negligible effect on the high voltage parts far away from the disturbance. Therefore, great accuracy is not necessary for networks that are less impacted and these parts can be considered as external subsystems required to aggregate.

1.2 Objectives and Research Questions

The goal of this project report is to have a tool for generating aggregated power system models with the appropriate level of details that can be used for power flow and stability study applications. The motivation to develop aggregated models raises due to the challenges in using detailed models mentioned in the problem statement. Therefore, the main objectives of this report are;

- To review the available model reduction and aggregation methods, tools and their application and demonstrate a selected method by a case study.
- To create an equivalent model for low voltage grid partitions and compare the performance of the developed model with the complete system model.
- To confirm that the equivalent aggregated model can be used for some major operating conditions with predefined performance criteria.
- To automate part of the model aggregation procedure using scripts in Phyton programming.
- To give a good insight about PSSE and phyton programming in which the reader can use it as a learning reference.

By making a literature review on the recently used aggregation methods, the following main research questions have been formulated in this report to address the basic requirements in dynamic equivalencing.

1. What model order to consider for each equivalent unit and how to cluster network areas so that the crucial properties of the external subsystem will be preserved?

2. How to determine the aggregated model parameters such as machine, load, branch, and control system parameters?

3. How and where to connect the dynamic equivalent aggregated units and how to represent the final aggregated dynamic model?

1.3 Scope and Limitation

Scope: According to the purpose of the model, different parties use several model versions with different degree of aggregations. However, these aggregated resources are not located in the grid with sufficient detailed network parameters and hence they are not relevant for dynamic stability studies. One practical approach to overcome these problems is to develop an aggregated model based on physical preservation and capture the main dynamics of the original power system model. Therefore, the scope of this report is to make literature on available dynamic grid aggregations and find the research gap to be filled. First, the static aggregation method applied in the pre-thesis report, which was tested for the IEEE 30 Bus Test Case, will be retested using the Norwegian power grid model. Since the grid network is very large, this will be performed only on part of the grid. The main focus will be in applying the proposed dynamic aggregation using python scripts to automate part of the grid aggregation and checking the validation of the equivalent aggregated results. Therefore, a complete aggregation automation of the given power grid model and including every power system components during the equivalencing process is beyond the scope of this report.

Limitation: For a very large network, it is difficult to study the aggregation of branches and therefore, the aggregation methodology discussed in this report doesn't consider the equivalencing of branches' data and their representation in the equivalent model. However, in the pre-thesis report [1], it has been studied how an equivalent branches are added to maintain the network admittance and the reader can refer to this report to get an overview on how congestion of tie-lines are managed and how additional equivalent branches are developed. To accurately aggregate grid model containing several model types it is required to consider several scenarios of grouping machines with similar governor, excitation system and/or power system stabilizers. This adds complexity to the aggregation process even though it will give more accurate results. Even though it is impractical to have an identical model of system components, the generators in the second case study are assumed to have the same type of governing and control system models.

1.4 Thesis Structure

This thesis report is partitioned into 7 chapters, including this introductory chapter. The remaining part of the report is organized as follows:

- **Chapter 2: Introduction to Dynamic Models** - gives general overview and definition of power system models and terminologies that are used in this paper. This part is therefore optional for a reader who has the basic knowledge about power system dynamic models.
- **Chapter 3: State-Of-The-Art Review** - discusses the literature and the research gap on dynamic aggregation methodologies. A step by step review on how to answer the identified research questions is presented in this chapter.
- **Chapter 4: Methodology and Software** - this chapter discusses the proposed methodology and the basic software setups. The case studies considered in this report are also described.
- **Chapter 5: Validation of Results and Applications of Grid Aggregation** - the measurement metrics to evaluate the resulting equivalent model's parameters are discussed in this chapter. In addition, this chapter gives the general highlight on further application areas of static as well as dynamic power grid aggregations.
- **Chapter 6: Results and Discussion** - a discussion and analysis of the results obtained from the proposed methodology are presented in this chapter.
- **Chapter 7: Conclusions and Future Work** - this chapter will take the reader to the concluding remarks and a brief answers to the research questions addressed in this thesis work, following some recommendations for further work.
- **Appendices A:** - The reader can refer to the appendices to look at further simulation results, Python scripts and network data of the case studies used in this report.

Chapter 2

Introduction to Dynamic Models

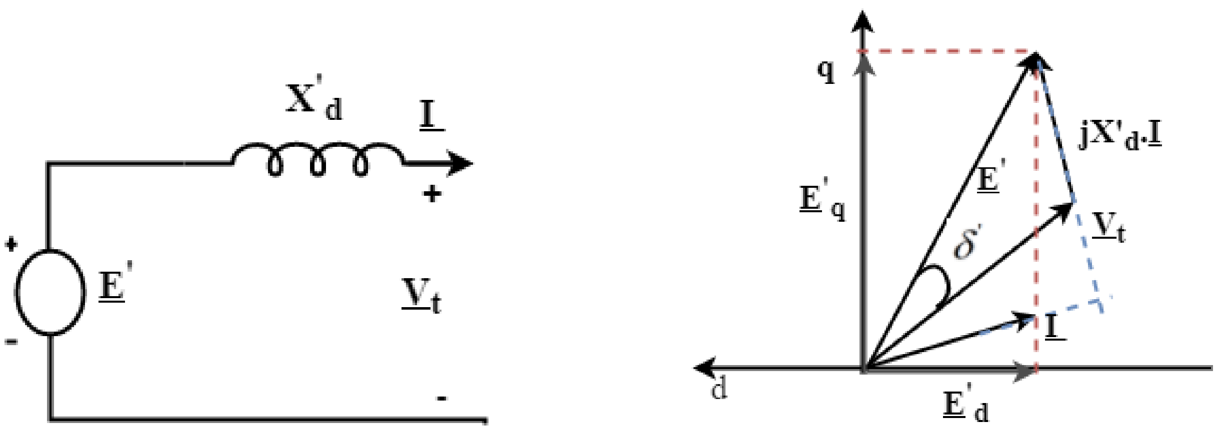
When we talk about power grid networks it is all about representing the components in the network using a mathematical models and all modeling is about simplifications. This is very much true when it comes to power systems containing several equipment models such as a generator, transmission line, control system devices, compensators and etc. The combination of all these individual models described using mathematical equations form the complete power system model. Depending on the size and technological advancement of the grid infrastructure, the power system grid consists several system components starting from a big generation unit up to a smaller household consumption devices. Therefore, dynamic simulations in power system require a good model of all the dynamic devices in the network. In particular, a generator unit needs a model including an exciter, governor, and power system stabilizer (PSS) models. The exciter and the governor control the reactive and active output powers of the generator, respectively. In addition, the excitation limiters are used to help the protection relays to work within their limits. Whereas, the PSS helps to damp the oscillatory behavior of the dynamic response. As it is mentioned in [7] machine, excitation system, Static Var control system and power system stabilizer models are the main dynamic models to consider in the power system dynamic studies. Thus, it is important to have a good understanding of these models and their dynamic characteristics' before looking deeper into the power system dynamics . In this section, the relevant dynamic power system models will be reviewed and this will be the basis for a coherency based dynamic equivalencing approach presented in chapter 3.

2.1 Synchronous Machine Models

In power system literature, several synchronous machine models have been studied for different dynamic stability analysis. According to [7], there are three widely used types of models to represent the synchronous machine: i) an electromechanical model, also called classical models, ii) a model including detailed parameters and transient effects, and iii) a model which further includes the sub-transient effects. The first two model types are briefly discussed in the next section.

2.1.1 Classical Generator Models

In using a classical generator approach, the generator models are represented by a rotor swing equation (2.1) with the rotor angles (δ) as state variables. These models are mathematically represented as a simplified versions of the detailed models under the assumption of constant internal transient emf ($E^{'}$) and ignoring the transient saliency ($x_d^{'} \approx x_q^{'}$) which allows to replace the two-axis model by one simple equivalent circuit [14]. The circuit and phasor diagram of this model are presented in Figure 2.1 under a further assumption of zero armature resistance.



(a) Circuit Diagram **(b) Phasor Diagram**

Figure 2.1: Classical Generator Model

The swing equation for this simplified model can be defined as;

$$\begin{aligned} M\tfrac{d\omega}{dt} &= P_m - P_e - D\omega \\ \tfrac{d\delta}{dt} &= \omega \end{aligned} \tag{2.1}$$

where M, ω, P_m, P_e and D are the inertia coefficient, angular speed, mechanical power, electrical power and damping coefficient of the generator, respectively. With the above simplifications, the electrical power of such models can be expressed as;

$$P_e = \frac{E^{'}V_s \sin\delta}{x_d^{'}} \tag{2.2}$$

Since this model is simplified under the assumption of constant rotor flux linkages, in other words, constant internal emf, all the dynamic studies using this model are performed considering constant emf from the excitation system [14].

2.1.2 Transient Generator Models

In analyzing a small signal stability studies using the classical model, only the basic dynamics of synchronous generators can be investigated. When a disturbance occurs, systems are continuously changing their state of operation and the induced emf of the generators will no longer be constant. A current is therefore induced in the q-axis rotor body as a result of the transient and sub-transient effects. Consequently, a voltage is induced in the d-axis and the impact needs to be investigated in separate axis [14], instead of using a simplified one-axis model. Therefore, in this transient generator model, the equivalent generator is represented by a two-axis model with an excitation system containing a field winding on the d-axis and a damper winding on the q-axis [42]. To include this impact in the dynamic model, the circuit and phasor diagrams of the classical model presented in Figure 2.1 can be resolved into d-q axis as shown in Figure 2.2.

A transient generator model of fourth-order resolved into d and q-axis can be described by the time domain rotor swing and electrical differential and algebraic equations (DAE) as;

$$\begin{aligned} M\tfrac{d\omega}{dt} &= P_m - P_e - D\omega \\ \tfrac{d\delta}{dt} &= \omega \end{aligned} \tag{2.3}$$

$$\begin{aligned} T_{do}^{'}.\tfrac{dE_q^{'}}{dt} &= E_f - E_q{'} + I_d.x_d - x_d{'} \\ T_{qo}^{'}.\tfrac{dE_d^{'}}{dt} &= -E_d{'} - I_q.x_q - x_q{'} \end{aligned} \tag{2.4}$$

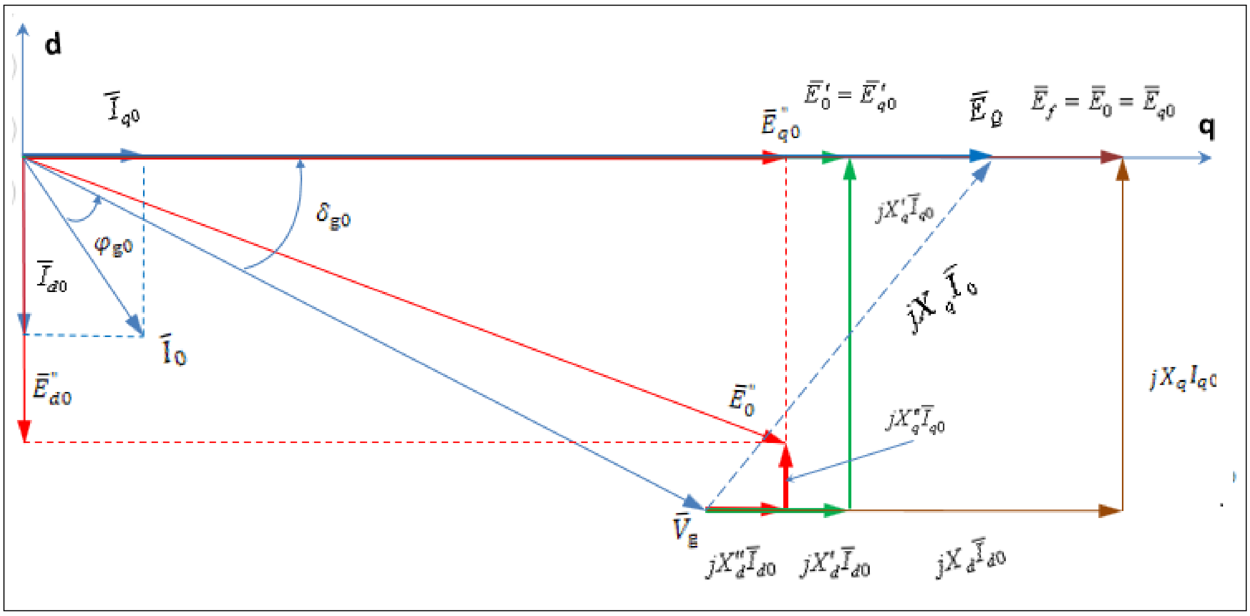


Figure 2.2: Phasor diagram of a transient synchronous generator

The differential equations (2.3) and (2.4) describe the mechanical and electrical operations of the generator whereas the algebraic equations in (2.5) describe its equivalent terminal voltage at a transient state, the same goes for sub-transient models.

$$\begin{aligned} V_d &= E_d^{'} - I_q.x_q^{'} \\ V_q &= E_q^{'} + I_d.x_d^{'} \end{aligned} \tag{2.5}$$

Using the terminal voltage expressions in equation (2.5), the transient saliency air-gap power of the generator can be calculated as, [14];

$$P_e^{'} = \left(E_d^{'}.I_d + E_q^{'}.I_q\right) + \left(x_d^{'} - x_q^{'}\right).I_q.I_d \tag{2.6}$$

Similar equation with sub-transient emfs and reactances can be used to determine the sub-transient air gap power.

2.2 Excitation System Models

To provide an excitation of DC field current supplied either by a DC generator or an AC generator with rectifiers, excitation or field control system is the most crucial part of power system industry [14]. The excitation circuit is consisting of an exciter and automatic voltage regulator which controls the field current. To meet the required DC current, several types of exciter configurations have been used in power system and several models exist for each typical excitation systems. A commonly used excitation system model named as IEEE type1 with exciter time constant T_E and exciter gain K_E is shown in Figure 2.3. This exciter model is used in the later chapters to illustrate how its parameters need to be estimated in aggregating a group of the same models.

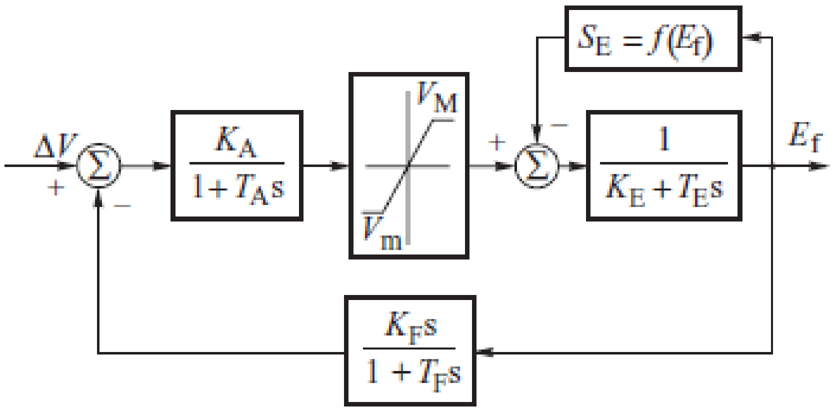


Figure 2.3: IEEE type 1 excitation system model [14]

As shown in Figure 2.3, the first-order transfer function with time constant T_A and gain K_A describes the voltage regulator followed by the voltage limiter of the AVR. The feedback block with time constant T_F and gain K_F represent the feedback stabilization signal to achieve acceptable transient performance [14]. The saturation characteristic of this exciter model is represented by a non-linear function $S_E = f(E_f)$ which is commonly approximated by exponential function[14].

2.3 Turbine-governor System Models

The operating speed of the synchronous generators driven by either gas, steam or hydro is controlled by the turbine governing system according to the required output power. Recently, the modern generators are being fitted with sophisticated digital governors that give a higher degree of functionalities to regulate the input power into the generator [14]. Depending on the type of turbine, either impulse or reaction turbine, the input power is controlled by regulating the inflow via needle or spear and wicket gates, respectively [14]. In both turbines, it is required to mathematically model how the turbine power changes with the position change of the regulating device. Due to the existence of extensive hydro-power generations in a case study considered for this thesis work, a simplified classical model of hydraulic turbines and their governing system (IEEE Type 2) shown in Figure 2.5 is considered for dynamic equivalencing.

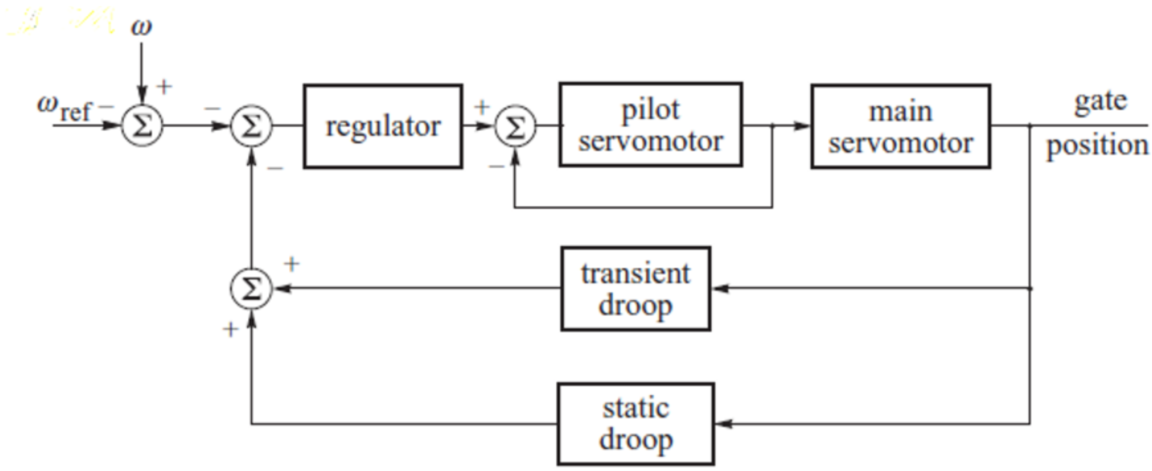


Figure 2.4: Functional diagram of hydraulic turbine governor. [14]

By applying a linear simplification to the functional diagram in Figure 2.4 the turbine governor system can be represented using a transfer function and gate position limiter, Figure 2.5. This simplification gives a model which is equivalent to the IEEE Type 2 Speed-Governing Model. The parameter K represents the governor gain while p_o and ω are the output power and speed to set the required gate position(p_b). The model parameters T_2, T_3 and T_4 are the governor lead/lag, gate actuator, and water starting time constants and the last block in the diagram is the gate position limiter.

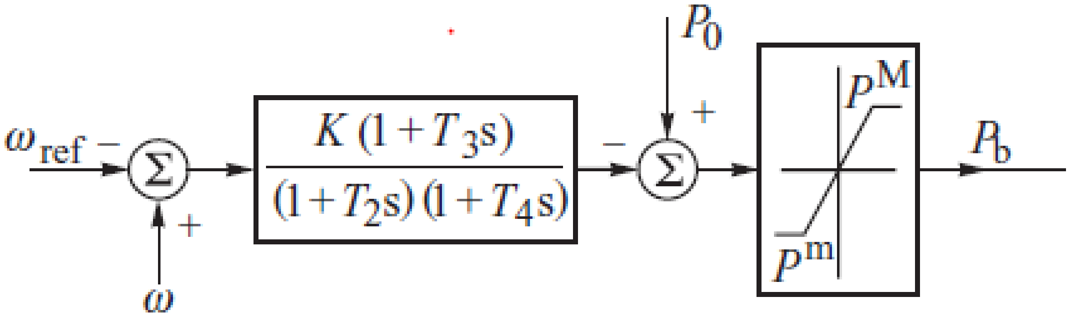


Figure 2.5: Simplified hydraulic turbine governor model [14]

2.4 Power System Stabilizer Models

Power system stabilizers (PSS) are the most used controllers to stabilize local and inter-area modes in a deregulated power system. The electromechanical oscillations caused by AVR and inter-area oscillations are damped by modulating the input signal of the excitation system through the PSS. To introduce a component of additional damping torque proportional to speed change, a PSS model connected to the excitation system with speed input, as discussed in [14], is considered for the dynamic studies presented in this paper.

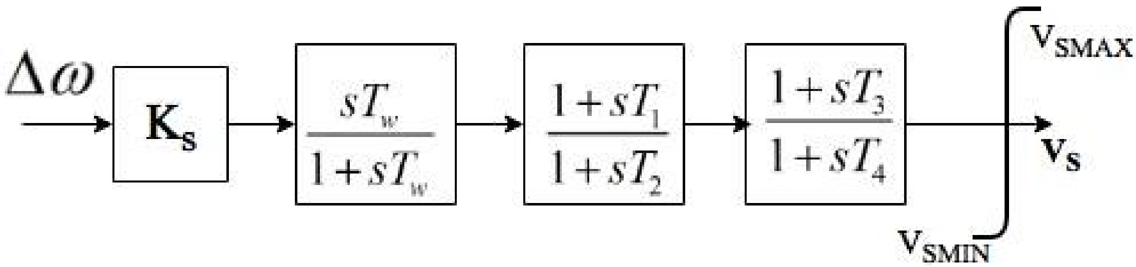


Figure 2.6: PSS model with speed input

The block diagram of this power system stabilizer is depicted in Figure 2.6 where K_S represents the stabilizer gain and T_w is the washout time constant. The time constants T_1 - T_4 describes the PSS lead/lag compensation time constants and the last block is the PSS output voltage limiter.

Chapter 3

State-of-The-Art Review

In determining a dynamic equivalent model, the methods discussed in this report are under the assumption that the complete interconnected power system is divided into internal (study) and external subsystems or areas, as shown in Figure 3.1. Based on the intended use of the grid model, this area definition can be given based on several factors such as load and generation conformity, grid voltage levels, geographic location, electrical distance, congestion severity, ownership groupings, etc. In some literature, a zone between the internal and external subsystems referred to as boundary area, the buses in red color, is considered. The boundary buses are then used to connect the equivalent models of the external subsystem. In the internal area where it is important to analyze the detailed behavior of the subsystem, a complete dynamic model of loads, generator units and associated controllers are used. While in the external subsystem, detail information of the system is not required and the subsystem can be replaced by an aggregated model. Dynamic model aggregation also referred to as dynamic equivalencing, is the process of reducing the complexity of the external subsystem while preserving its impact on the study system. Therefore, only the external system is of interest and the study system is kept untouched during the aggregation process.

There are several different aggregation approaches of power system models. Usually, they are grouped into two broad categories called model-based and measurement-based dynamic equivalencing. The first approach is about aggregating the mathematical models of the power grid components based on their system parameters. Whereas the second one is using observations or measurements of state variables at a specified study area to determine the combined effect. In the following subsections, both the model-based and measurement-based dynamic aggregation approaches are reviewed. Since the objective of this report is to preserve the dynamics of the aggregated part of the grid, the main focus will be given to model-based aggregation techniques.

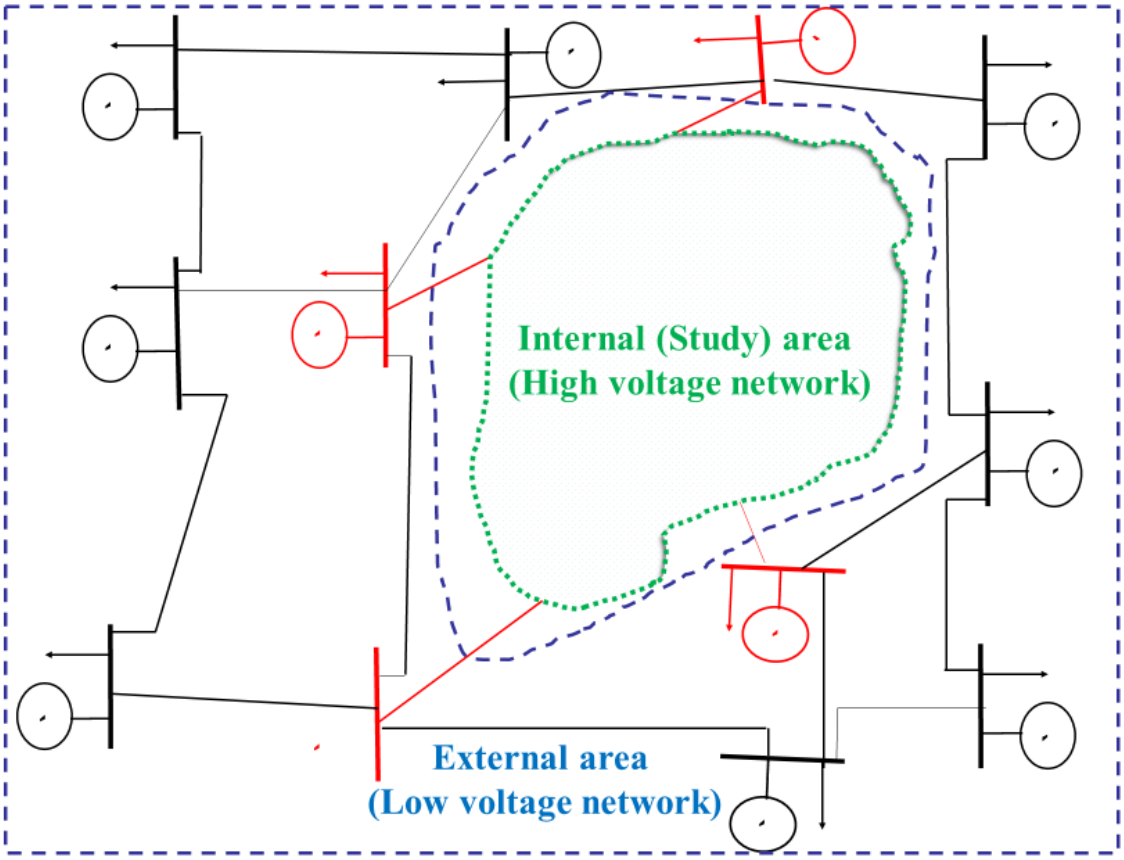


Figure 3.1: Separation of a grid model into study and external subsystems.

3.1 Model-Based Dynamic Aggregation

Model-based equivalencing methods depend on developing a detailed aggregated model parameters such as inertia, transient reactance, transformer reactance, transmission line data, load data, controller parameters' and different circuit component statuses [4]. In another word, this is referred to determining a reduced order model of a given subsystem. Therefore, these aggregation techniques depend on the precise knowledge of the model parameters in each area. Applying this technique to a very large power system model to be aggregated is one of the most accurate and in many cases most difficult and time-consuming process [36].

Depending on how the model parameters in the detail model are grouped, to estimate the values of the aggregated parameters in the equivalent lower order model, model-based aggregation techniques can be categorized as; coherency-based [16, 17, 41, 39, 8, 20] and modal analysis based [36, 23, 40, 9, 28, 13, 29, 34, 35, 25, 21] dynamic aggregation techniques. This section presents the formulation of these two dynamic equivalencing techniques.

3.1.1 Coherency Based Dynamic Aggregation

For coherency based techniques, some authors referred it as a physical reduction because of the ability to preserve the physical network parameters, it is assumed that disturbances are introduced in the internal subsystem boundary buses and dynamic response in the external subsystem need to be studied. Following the response, dynamic models with similar dynamic response, e.g. the generator rotor angle response, are considered as coherent groups and they need to be replaced by one equivalent and aggregated unit [16]. The main idea is to reduce the number of dynamic model representations in the external system while preserving their impact on the study (internal) subsystem [17]. The procedure to build the reduced order model of dynamic power system model using this technique can be divided into three steps [17, 41, 39, 8, 25, 21]: Coherency identification, Network topology reduction and Dynamic aggregation of coherent generators and their control systems.

1. Coherency Identification:

One of the most important steps and maybe the most challenging part of building an efficient dynamic equivalent model is identifying which grid components should be grouped together to keep the system dynamics after the internal subsystem is perturbed. Doing this one can develop good equivalent models by aggregating individual nodes and generators in the same group. The aggregation of nodes at which the equivalent bus is established is accomplished by an equivalent network admittance calculation which depends on the transformation ratio given as;

$$\widehat{v}_i = \frac{v_i(t)}{v_a(t)} = \frac{\widehat{v}_i}{\widehat{v}_a} \approx constant \tag{3.1}$$

Where v_a and v_i are the voltages of the equivalent node and the aggregated node at bus i. Similarly for any nodes i and k in the external subsystem, equation (3.1) can be expressed as [25, 14];

$$\widehat{v}_{ik} = \frac{v_i(t)}{v_k(t)} = \frac{\widehat{v}_i}{\widehat{v}_k}.e^{j[\delta_i(t)-\delta_k(t)]} \approx constant \tag{3.2}$$

After a disturbance in the internal subsystem, the nodes satisfying equation (3.2) are referred as coherent nodes. If the voltage magnitudes of the coherent nodes are assumed to be constant, as for PV nodes power flow in steady-state [14], the coherency condition in equation (3.2) can be simplified to;

$$\delta_{ik}(t) = \delta_i(t) - \delta_k(t) = \varepsilon_{ik}(t) \tag{3.3}$$

However, as it is mentioned in [14] *"Practical experience with power system simulation shows that the load nodes are almost never electrically coherent."* Therefore, the generator buses are used to identify the coherent nodes to find the equivalent node. Then, the loads in the external subsystem are distributed among the equivalent generator nodes, similar to the ward equivalent technique discussed in the specialization project report, [1]. However, in the pre-thesis report, it has been studied that a ward equivalent is not an efficient equivalencing method for dynamic equivalent models and a sensitivity based load bus coherency identification is proposed instead. Since the nodal voltage at a classical generator model is equal to the transient emf, which is assumed to be constant, the coherency condition in equation (3.3) can be used to check if machine i and k are electromechanically coherent. For detailed generator models, the effect of non-constant transient emf is taken into consideration by including the corresponding aggregated model of the excitation system. To further investigate the coherency tolerance measure resulting from rotor angle response the coherency duration time t_c can be included in the coherency condition in equation (3.3). This will help to analyze the coherency for the entire simulation time and can be expressed as;

$$|\delta_i(t) - \delta_k(t)| < \varepsilon_{\Delta\delta} \quad \text{and} \quad t \leq t_c \tag{3.4}$$

Using a magnitude measure of the rotor angle response the generators are therefore considered as they are exactly coherent if $\varepsilon_{\Delta\delta} = 0$ and $t_c = \infty$. But, practically the exact coherency does not exist and hence it is required to consider a coherency tolerance, $\varepsilon_{\Delta\delta} \neq 0$. Therefore, two generator buses in external subsystem are considered as coherent generators, if their rotors swing together, i.e. their angular difference remains less than a certain tolerance for the entire simulation time [41, 39]. The coherency definition from equation (3.3) can be investigated in terms of phase $\phi_{\varepsilon(t)}$ or/and magnitude, $|\varepsilon_{ik}(t)|$, of the time domain rotor angle response, $\delta_{ik}(t)$.

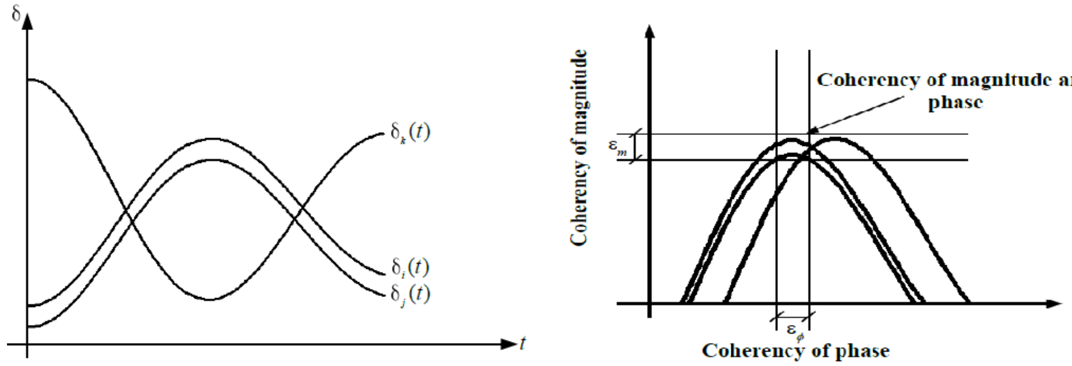


Figure 3.2: Coherency measures magnitude and phase coherency [24]

According to power system studies like in [8, 14, 24], the synchronism of the generators in the external subsystem is affected by the location of the disturbance in the internal subsystem. The further away the disturbance is from the external generator nodes, the less will be the loss of synchronism among these generators i.e. the more they are close to being exact coherent groups. So, the generators within the external system are supposed to have similar rotor angel swing characteristics under disturbances in the internal subsystem. For this reason, magnitude coherency approach is widely used to preserve electromechanical modes of the external subsystem during the dynamic equivalencing process[24]. For generators i and j to be investigated, the magnitude coherency can be computed using Euclidean Distance ($d_{i,j}$) of the time domain rotor angle response over a simulation time (t_c), [24].

$$d_{i,j} = \sum_{t=t_1}^{t_c} \sqrt{(\varepsilon_{ij}(t))^2} \tag{3.5}$$

Then generators with smaller, ideally zero, ($d_{i,j}$) values in equation (3.5) are coherent generators and those generators can be aggregated into one unit. Figure 3.2 shows, for generators i, j and k : generator i is coherent with generator j, as their rotor angles are swinging together with small magnitude difference while generator k is not coherent with the group of the other two, the rotor swings in opposite direction.

2. Network Topology Reduction:

Since the main purpose of the coherency-based aggregation is to reduce dynamic model parameters of the system, the size of the grid in the external subsystem is reduced by eliminating load buses and aggregating generator terminal buses. The loads in the eliminated buses are then distributed to the electrically closest aggregated generator buses. Several methods of node aggregation have been reported in the literature. The most commonly used methods are ; Extended Ward equivalent [25, 1, 3], in some literatures referred as Gaussian elimination, Thevenin's equivalent [25], Radial Equivalent Independent (REI) [18], Zhukov's method [14, 6] and multi-machine representations [25, 6]. The principle of Radial Equivalent Independent and the mathematical derivation of Ward equivalent method can be found in the pre-thesis report,[1]. In this project work, it has been studied that the Ward equivalent method is not efficient to model reactive power support from the external subsystem. This is because the loads are modeled as constant admittance and hence it is only valid for PV characteristic loads. Zhukov's node aggregation method that is based on two basic aggregation conditions can be used to overcome this problem [14]. The first condition is the currents and voltages of the retained nodes does not change during aggregation. Secondly, the active and reactive power of the equivalent node must be equal to the sum of the active and reactive power injections at the aggregated nodes.

Then, the aggregated equivalent model is constructed by equivalencing the admittance matrix of the external system that is needed to be simplified. The admittance matrix equation of the external subsystem can be expressed in the partitioned form:

$$\begin{pmatrix} I_R \\ I_D \end{pmatrix} = \begin{pmatrix} Y_{RR} & Y_{RD} \\ Y_{DR} & Y_{DD} \end{pmatrix} . \begin{pmatrix} V_R \\ V_D \end{pmatrix} \tag{3.6}$$

Where I_R and V_R are the current injection and voltage at the nodes to be retained and I_D and V_D are node current injection and voltage at the nodes to be deleted.

For an equivalent network, the desired form of equation (3.6) is explicitly involving only I_R and V_R where I_D and V_D are represented by the equivalent network of the deleted buses. The expression for V_D is then obtained by rearranging the second row in equation (3.6) as;

$$V_D = Y_{DD}^{-1}.\,(I_D - Y_{DR}.V_R) \tag{3.7}$$

and substituting this into the first row of equation (3.6) the currents injected into the retained study subsystem can be determined as:

$$I_R = (Y_{RR} - Y_{RD}.Y_{DD}^{-1}.Y_{DR}).V_R + Y_{RD}.Y_{DD}^{-1}.I_D \tag{3.8}$$

The first term in equation (3.8) specifies a set of equivalent branches and static shunt elements connected to the retained nodes, while the second term specifies a set of equivalent currents that must be impressed on the retained nodes to reproduce the effect of load currents at the deleted nodes. These equivalent currents may be transformed into equivalent constant real and reactive power loads at the retained buses.

3. Dynamic Aggregation of Coherent Groups:

After the network is reduced using the elimination and aggregation methods mentioned in the second step, the model is ready for steady-state analysis [14]. To use the developed model for dynamic stability studies the equivalent generator units and corresponding controllers must be added to the equivalent nodes. Then the coherent generators, identified in the first step, can be aggregated to an equivalent single generator model that can still preserve the impact of machines on the external subsystem onto the study subsystem. The same goes for the other power system dynamic models, generator, and system controller models.
To answer the research questions formulated in doing this project work, the procedures of aggregating coherent groups identified in the first step are discussed in the following section.

1. What model order to consider for each equivalent unit and how to cluster network areas so that the crucial properties of the external system will be preserved?

Before looking deeper into the process of aggregating the model, the common question to answer is what assumptions and simplifications are considered in representing the individual units. Therefore, to address this question in equivalencing the machines, generally, the coherent generators can be represented using classical model [39, 25, 24] with the assumption of constant transient emf. When it is desired to have a model for the purpose of detailed dynamic stability, a detailed aggregation of the generators and their corresponding controllers need to be considered [39, 24]. The choice of the order of the equivalent model is then determined by how the machines in the external subsystem are impacting the study subsystem. If they have a less dynamic impact, then they can be represented using a classical model and controller aggregations can be ignored. But when the dynamics of the coherent generators have a significant impact then they need to be represented using a detail model parameters and the corresponding system controllers need to be considered during the dynamic equivalencing.

In aggregating classical models, generators in each coherent group are represented by an equivalent single classical generator model [41, 8]. As a result, the equivalent generator is represented by a rotor swing equation and a constant transient emf $E_a^{'}$ behind the transient reactance $X_{d,a}^{'}$ connected to a common bus with terminal voltage of $V_{t,a}$, as shown in Figure 3.3.

In the aggregation studies where detail dynamic equivalencing are required, the equivalent generators are described using a two-axis transient machine and associated control system models. Assuming there are m number of coherent generators in the same coherent group, similar to the single generator model, the swing equation, and two-axis model of the i^{th} generator can be represented by the following time domain equations:

$$\begin{aligned} & M_i \tfrac{d\omega_i}{dt} = P_{m,i} - P_{e,i} - D_i\omega_i \\ & \tfrac{d\delta_i}{dt} = \omega_0\omega_i \\ & T_{do,i}^{'}.\tfrac{dE_{q,i}^{'}}{dt} = E_{f,i} - E_{q0,i}^{'} + I_{d,i}.(x_{d,i} - {x_{d,i}}^{'}) \\ & T_{qo,i}^{'}.\tfrac{d{E_{d,i}}^{'}}{dt} = -E_{d0,i}^{'} - I_{q,i}.(x_{q,i} - {x_{q,i}}^{'}) \end{aligned} \qquad i = 1,2,3...m \tag{3.9}$$

Where M_i, ω_i, $P_{m,i}$, $P_{e,i}$ and D_i are the inertia coefficient, angular speed, mechanical power, electrical power and damping coefficient of generator i , respectively and $T_{do,i}^{'}$ and $T_{qo,i}^{'}$ are the transient open circuit time constants in d and q-axis respectively.

For a classical model shown in Figure 3.3, the generator is represented by the armature voltage equations with transient emfs $E_{d,i}^{'}$ and $E_{q,i}^{'}$ behind the transient reactances $x_{d,i}^{'}$ and $x_{q,i}^{'}$.

$$\begin{aligned} V_{d,i} &= E_{d,i}^{'} - I_{q,i}.x_{q,i}^{'} \\ V_{q,i} &= E_{q,i}^{'} + I_{d,i}.x_{d,i}^{'} \end{aligned} \qquad i = 1,2,3...m \tag{3.10}$$

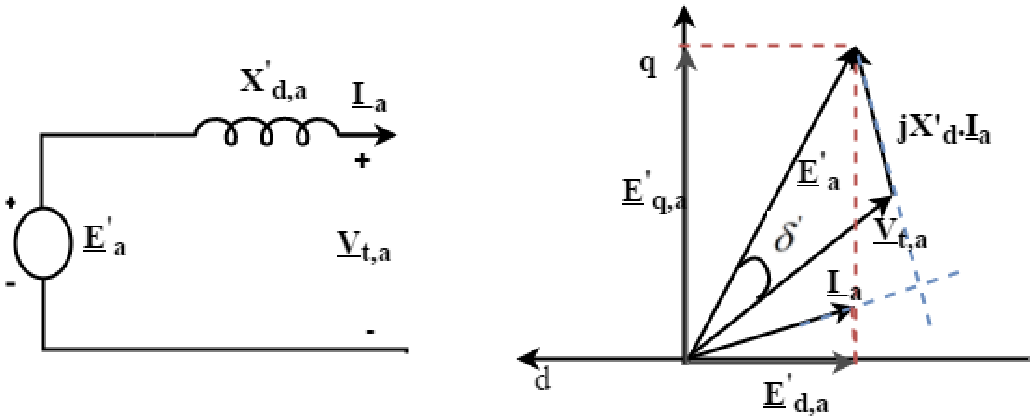


Figure 3.3: Classical equivalent generator model

Using equation (3.10) the i^{th} generator's current can be written as;

$$\begin{pmatrix} I_{d,i} \\ I_{q,i} \end{pmatrix} = \begin{pmatrix} 0 & 1\big/x'_{d,i} \\ -1\big/x'_{q,i} & 0 \end{pmatrix} . \begin{pmatrix} V_{d,i} & - & E'_{d,i} \\ V_{q,i} & & E'_{q,i} \end{pmatrix} \tag{3.11}$$

The transient air-gap electrical power of generator i in equation (3.11) is expressed as follows and the same goes to sub-transient state.

$$P'_{e,i} = \left(E'_{d,i}.I_{d,i} + E'_{q,i}.I_{q,i}\right) + \left(x'_{d,i} - x'_{q,i}\right).I_{q,i}.I_{d,i} \tag{3.12}$$

Each coherent group is then represented by an equivalent generator with corresponding aggregated model parameters and all the parameters in the above equations are based on the same MVA base value. As a result, the number of differential and algebraic equations in equations (3.9 - 3.12) will be reduced to represent only the equivalent models which significantly minimizes the computation burden of these equations.

2. How to determine the aggregated model parameters such as machine, load, branch, and control system parameters?

Once the desired order of the model is specified, the next step is to address the second research question on how to extract the model parameters from the complete model and develop the equivalent aggregated parameters. The determination of these aggregated model parameters of the main power system components is presented in the following section.

3.1.1.1 Dynamic Aggregation of Generators

a.1 Equivalent Mechanical Parameters:

Since coherent generators are identified to swing in the same direction, have similar rotor angle δ, according to [14, 6] these generators can be treated as if they are rotating on one common rigid shaft. Consequently, the mechanical power, inertia and damping constants of the equivalent unit can be calculated by adding the individual generator unit parameter values, [41, 8, 21, 42] which are defined as:

$$\begin{aligned} &P_{m,a} = \sum_{i=1}^{m} P_{m,i}, M_a = \sum_{i=1}^{m} M_i \quad \text{,and} \quad D_a = \sum_{i=1}^{m} D_i \\ &i = 1,2,3\ldots m \end{aligned} \tag{3.13}$$

Where $P_{m,a}$, M_a and D_a are the aggregated mechanical power, inertia and damping constants of the equivalent generator, respectively.

a.2 Equivalent Electrical Parameters:

Electrical power of the equivalent unit, both active and reactive powers, are determined the same way as the mechanical power while the time constants [6], voltage magnitudes and phase angles are estimated based on the average values. These equivalent aggregated parameters can be determined as follows [41, 8, 21, 42],

$$\begin{aligned} P_{e,a} &= \sum_{i=1}^{m} P_{e,i}, Q_a = \sum_{i=1}^{m} Q_i \\ V_{t,a} &= \frac{\sum_{i=1}^{m} V_{t,i}}{m}, \theta_{t,a} = \frac{\sum_{i=1}^{m} \theta_{t,i}}{m} \end{aligned} \qquad i = 1,2,3\ldots m \tag{3.14}$$

According to [21, 42, 32], the equivalent generators' reactances of the equivalent generator model can be obtained by:

$$\begin{aligned} X_{d,a} &= 1 \Big/ \sum_{i=1}^{m} a_i.\left(\frac{\cos^2(\delta_i-\delta_a)}{X_{d,i}} + \frac{\sin^2(\delta_i-\delta_a)}{X_{d,i}}\right) \\ X_{q,a} &= 1 \Big/ \sum_{i=1}^{m} a_i.\left(\frac{\cos^2(\delta_i-\delta_a)}{X_{q,i}} + \frac{\sin^2(\delta_i-\delta_a)}{X_{q,i}}\right) \end{aligned} \qquad i = 1,2,3\ldots m \tag{3.15}$$

Where $X_{d,a}$ and $X_{q,a}$ are the d-axis and q-axis steady state reactances of the equivalent generator and a_i is the turns ratio or transformation ratio defined in equation (3.1). The same expression in equation (3.15) can be used to calculate the transient and sub-transient reactances of the equivalent generators with corresponding transient and sub-transient rotor angles, respectively.

Under the assumption of a perfect generator coherency ($\delta_i - \delta_a \approx 0$), where the angular difference between the rotor angles of these generators is very small and negligible equation (3.15) can be simplified into parallel reactance connections. This results in paralleling the reactances of all the coherent generators as;

$$X_{d,a} = 1 \Big/ \sum_{i=1}^{m} \frac{1}{X_{d,i}} \quad \text{and} \quad X_{q,a} = 1 \Big/ \sum_{i=1}^{m} \frac{1}{X_{q,i}} \quad i = 1,2,3...m \tag{3.16}$$

<u>a.3 Equivalent's Transient Time Constant:</u>

According to the aggregation methods proposed in [42, 22], the transient open circuit time constants of the equivalent generators are obtained to be the aggregated state variables of the individual coherent machines.

Combining the last two differential equations in (3.9) and (3.11) the generator model can be written as:

$$\begin{pmatrix} \frac{dE'_{d,i}}{dt} \\ \frac{dE'_{q,i}}{dt} \end{pmatrix} = \begin{pmatrix} -1\Big/T'_{qo,i} & 0 \\ 0 & -1\Big/T'_{do,i} \end{pmatrix} . \begin{pmatrix} E_{d,i} \\ E_{q,i} \end{pmatrix} + \begin{pmatrix} 0 \\ 1\Big/T'_{do,i} \end{pmatrix} .E_{fd,i} \tag{3.17}$$

For both generator i and the equivalent generator a of the coherent group equation (3.17) can be expressed in a matrix form C_a and the above equation can be splitted into two equations.

$$\dot{E}'_i = C_i.E_i + D_i.E_{fd,i} \quad \text{and} \quad \dot{E}'_a = C_a.E_a + D_a.E_{fd,a} \tag{3.18}$$

The equivalent transient open circuit time constants are then aggregated using the equivalent matrix C_a as:

$$T'_{do,a} = {}^{-1}\!/_{C_{a22}} \quad \text{and} \quad T'_{qo,a} = {}^{-1}\!/_{C_{a11}} \tag{3.19}$$

The matrices C_a and D_a are obtained using the coefficient matrix and the detail derivations can be found in the appendix part of [22].

3.1.1.2 Load Bus Aggregation

As it is mentioned in the previous section, coherent generators can be clustered together using the coherency criteria defined in equation (3.3) and the corresponding equivalent generator can be used for transient stability analysis. But, a system disturbance in the study area impacts not only the generator buses but also the dynamics of load buses. Thus, it is important to know which load bus needs to be associated to which coherent generator group and to apply an appropriate clustering of load buses.

A ward equivalent method also called Kron reduction, which is based on bus elimination approach is commonly used technique to aggregate the load buses. As it is studied in the pre-thesis report [1], using the bus elimination method loads are distributed to the electrically closest coherent generator buses. Since loads are converted into constant impedance equivalents, this method is no longer appropriate for stability analysis of dynamic loads. Another method of load bus aggregation proposed in [11] is based on generator influence factors. As it is correlated with voltage angle and voltage magnitude dynamics this method will be adopted in this project work. This approach is proposed with the following necessary assumptions about the power system under consideration. Firstly, all transmission lines are assumed to have a high reactance to resistance ratio and all the loads are modeled as ZIP (constant impedance, current, and power) loads. Secondly, all synchronous generators are assumed to be second order model. Finally, no FACTS compensators, like SSSC, SVC, etc. are considered in the aggregation process.

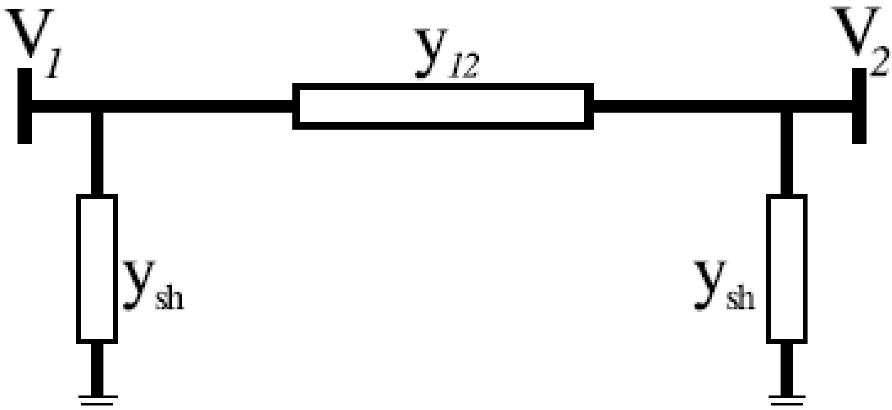


Figure 3.4: Typical π transmission line model

Considering a typical power transmission line as shown in Figure 3.4, assuming high reactance to resistance ratio the active and reactive power equations can be derived from the complex power equation.

$$\begin{aligned} P_{12} &= |v_1|\,.\,|v_2|\,.b_{12}.\sin(\theta_1 - \theta_2) \\ Q_{12} &= |v_1|\,.\,|v_2|\,.b_{12}.\cos(\theta_1 - \theta_2) \end{aligned} \tag{3.20}$$

In most usual case, the voltage angle differences between the buses are small and assuming $|v_1|$ and $|v_2|$ do not change very much equation (3.20) can be simplified further into:

$$\begin{aligned} P_{12} &= |v_1| \, . \, |v_2| \, .b_{12}.\theta_{12} \\ Q_{12} &= |v_1| \, . \, |v_2| \, .b_{12}.1 \end{aligned} \tag{3.21}$$

Equation (3.21) shows that the active power P_{12} and reactive power Q_{12} are more sensitive to voltage angle differences and voltage magnitudes, respectively. Based on these observations, the load bus can be clustered based on the relative voltage phase angle deviation during system disturbance under the influences of fluctuation of active injection, which eventually originate from generators. Another advantage of using the criterion of voltage phase angle rather than voltage magnitude is that the voltage magnitude is more easily to be changed due to relatively more reactive power sources supplied by reactive power compensator or transformer with tap changer.

In building the dynamic equivalent using classical aggregation, where the induced emf is assumed to be constant, the aggregation of coherent generators is performed with no consideration of the control systems like turbine and governor, AVR, PSS, and excitation system. However, the classical approach is not efficient when the control systems of the external subsystem have a significant impact on the transient stability analysis of the study area. Therefore, a detailed aggregation approach should be considered to include the effect of the excitation system on the coherency identification. In the next section, a discussion on the aggregations of these control system parameters is presented.

3.1.1.3 Dynamic Aggregation of Excitation System

To observe the impact of an excitation system on the identification of coherent machines, effects of field circuit dynamics need to be added to the equivalent dynamic model. The investigations made in [10] shows that the speed of AVR voltage variations has a significant influence on the coherency of generators. Therefore, it is necessary to consider the impact of the excitation system of generators to improve the accuracy of the dynamic aggregation. Assuming the IEEE-type 1 excitation system to all generators, the aggregated parameters of the equivalent excitation system can be determined according to the linear aggregation methods proposed in [28, 21, 22, 10, 42]. The dynamics of this excitation system can be described by adding the following differential equations into equation (3.9), [28, 10]

$$\begin{aligned} T_{E,i}.\tfrac{dE_{fd,i}}{dt} &= -(K_{E,i} + S_E(E_{fd,i})).E_{fd,i} + V_{R,i} \\ T_{A,i}.\tfrac{dV_{R,i}}{dt} &= -V_{R,i} + K_{A,i}.R_{f,i} - \tfrac{K_{A,i}.K_{F,i}}{T_{F,i}}.E_{fd,i} + K_{A,i}.(V_{ref,i} - V_i) \\ T_{F,i}.\tfrac{dR_{f,i}}{dt} &= R_{f,i} + \tfrac{K_{F,i}}{T_{F,i}}.E_{fd,i} \end{aligned} \tag{3.22}$$

Where $T_{A,i}$, $T_{E,i}$, $T_{F,i}$ and $K_{A,i}$, $K_{E,i}$, $K_{F,i}$ are the time constants and gain constants of the voltage regulator, exciter and stabilizer respectively and $R_{f,i}$ represents the regulator stabilizing transformer state variable.

The next step is to determine the aggregated values of these parameters and develop the equivalent excitation system for each coherent generator groups. Using a linearized state equation from the block diagram of the IEEE type 1 excitation system, shown in Figure 2.3, the corresponding parameters of the equivalent excitation system can be estimated as follows, [22, 42].

b.1 Equivalent Voltage Regulator Parameters:

$$\begin{gathered} K_{A,a} = \sum_{i=1}^{m} \frac{K_{A,i}}{T_{A,i}} \Bigg/ \sum_{i=1}^{m} \frac{1}{T_{A,i}} \quad , \quad T_{A,a} = m \Bigg/ \sum_{i=1}^{m} \frac{1}{T_{A,i}} \\ \text{and} \quad V_{RMAX,a} = T_{E,a}.\sum_{i=1}^{m} \frac{V_{RMAX,i}}{T_{E,i}}.d_k \end{gathered} \tag{3.23}$$

b.2 Equivalent Exciter Parameters:

Knowing the parameter values of the individual IEEE exciter models the corresponding values of the equivalent model can be estimated as:

$$\begin{aligned} &K_{E,a} = -\sum_{i=1}^{m} \tfrac{S_{E,i}}{m} \quad \text{and} \quad T_{E,a} = 1 \Big/ \sum_{i=1}^{m} \tfrac{d_i}{T_{E,i}} \\ &, \quad V_{RMAX,a} = T_{E,a}.\sum_{i=1}^{m} \tfrac{V_{RMAX,i}}{T_{E,i}}.d_i \\ &E_{FDMAX,a} = \sum_{i=1}^{m} \tfrac{V_{RMAX,i}}{K_{E,i}+S_{EMAX,i}} \quad , \\ &S_{EMAX,a} = -K_{E,a} + \tfrac{V_{RMAX,a}}{E_{FDMAX,a}} \end{aligned} \tag{3.24}$$

where

$$d_i = T''_{d0,i}.X''_{d,i}.\frac{\cos(\delta_i - \theta_{t,a})}{T'_{d0,i}x'_{d,i}} \tag{3.25}$$

b.3 Equivalent Stabilizing Circuit Parameters:

Assuming the same types of excitation system models as discussed in chapter 2 the equivalent gain and time constants, the values of the voltage stabilizer are determined as :

$$K_{F,a} = \frac{T_{F,a}.T_{E,a}}{m}.\sum_{i=1}^{m} \frac{K_{F,i}}{T_{F,i}.T_{E,i}} \quad \text{and} \quad T_{F,a} = m \Bigg/ \sum_{i=1}^{m} \frac{1}{T_{F,i}} \tag{3.26}$$

3.1.1.4 Dynamic Aggregation of Turbine-governor

Similar to the excitation system, finding the equivalent model parameters of turbine governors containing several model types is a big challenge as the response of each individual turbine-governor system has different characteristics. However, considering similar simplifications, the parameters of the equivalent models can still be aggregated using the same procedures as the dynamic aggregation of excitation systems. In this paper, the same type of turbine, hydraulic turbine, is assumed for all coherent groups. This is because the simplified hydraulic turbine governor model is similar to steam turbine governors when considering a classical linear turbine model [14]. Comparing the aggregation of steam turbine governor presented in [22] with aggregation of hydraulic turbine discussed in [42], the equivalent parameters of the hydraulic turbine governing system shown in Figure 2.5 can be obtained as;

$$K_a = \frac{1}{\sigma_a} = \frac{\sum_{i=1}^{m} K_i}{m} \quad \text{and} \quad T_{k,a} = m \Big/ \sum_{i=1}^{m} \frac{1}{T_{k,i}} \quad \textit{for k=2,3 and 4} \tag{3.27}$$

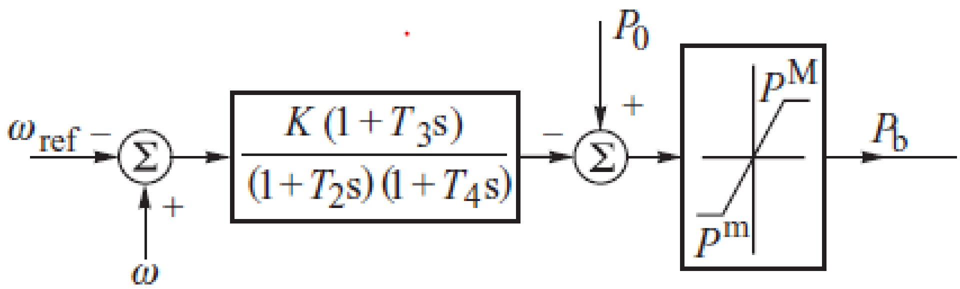


Figure 3.5: Simplified hydraulic turbine governing system model [14]

3.1.1.5 Dynamic Aggregation of Power System Stabilizer

Considering a speed input power system stabilizer, the parameters of the equivalent power system stabilizer can be evaluated using the similar procedures used for aggregation of excitation system.

According to the stabilizer aggregation presented in [42], the mathematical equations to estimate the equivalent model parameters are listed below;

c.1 PSS Time Constants:

$$
\begin{aligned}
T_{3,a} &= \frac{T_{w,a}.T_{2,a}.T_{4,a}}{m(T_{w,a}-T_{1,a})}.\left[\sum_{i=1}^{m}\frac{T_{3,i}.(T_{w,i}-T_{1,i})}{T_{w,i}.T_{2,i}.T_{4,i}}\right] \\
T_{1,a} &= T_{w,a}.\left[1-\frac{T_{2,a}}{m}.\sum_{i=1}^{m}\frac{T_{w,i}-T_{1,i}}{T_{2,i}.T_{w,i}}\right] \\
\text{and} \quad T_{k,a} &= m\Big/\sum_{i=1}^{m}\frac{1}{T_{w,i}} \quad \textit{for k=2, 4 and w}
\end{aligned}
\tag{3.28}
$$

c.2 Equivalent PSS Limit and Gain Constant:

$$
\begin{aligned}
V_{SLIM,a} &= \frac{S_{EMAX,a}+K_{E,a}}{K_{A,a}}.\sum_{i=1}^{m}\frac{d_i.K_{A,i}.V_{SLIM,i}}{S_{EMAX,i}+K_{E,i}} \\
K_{S,a} &= \frac{T_{A,a}}{m.K_{A,a}}.\sum_{i=1}^{m}\frac{K_{A,i}.K_{S,i}}{T_{A,i}}
\end{aligned}
\tag{3.29}
$$

where $K_{A,i}$, $T_{A,i}$ and $S_{EMAX,i}$ are parameters of the i^{th} exciter system and $K_{A,a}$, $T_{A,a}$ and $S_{EMAX,a}$ are the parameters of the equivalent aggregated exciter model determined from the aggregate excitation systems.

3. How and where to connect the dynamic equivalent aggregated units and how to represent the final aggregated dynamic model?

Once the equivalent generator and their corresponding control system parameters are estimated, the last step will be to know where and how to connect the equivalent dynamic models into the study subsystem. For load flow calculations, the aggregated generators can be connected directly to the transmission grid, but it is not satisfactory for dynamic studies. To preserve the power flow [6] and improve the dynamic representation, the aggregated buses need to be connected through ideal transformers and phase shifters. The turn ratio of this ideal transformer is defined as, [41],

$$
\dot{a}_k = \frac{\dot{V}_k}{\dot{V}_t} \tag{3.30}
$$

Where $\dot{V}_k$ and $\dot{V}_t$ are the voltages at bus k from external system and bus t is the equivalent aggregated bus of the coherent generator buses. This turns ratio is equal to the transformation ratio defined in equation (3.1).

As it is studied in [6], there are three available algorithms to aggregate coherent generators in power system toolbox. These algorithms are Podmore , Inertia aggregation and slow-coherency methods. Using Podmore algorithms coherent machines are moved to a common terminal bus while in the other two methods they are aggregated and moved to a common internal bus [6]. According to the bus elimination and aggregation methods such as ward equivalent, the equivalent generators are connected to the electrically closest internal buses. Further information on how external generators are moved to the internal subsystem can be found in the pre-thesis report, [1].

Finally, the complete reduced order model for the external system is described using the equivalent system parameters as:

$$\begin{aligned}
&M_a.\tfrac{d\omega_a}{dt} = P_{m,a} - P_{e,a} - D_a\omega_a \\
&\tfrac{d\delta_a}{dt} = \omega_a \\
&T'_{do,a}.\tfrac{dE'_{q,a}}{dt} = E_{f,a} - E'_{q0,a} + I_{d,a}.(x_{d,a} - x'_{d,a}) \\
&T'_{qo,a}.\tfrac{dE'_{d,a}}{dt} = -E'_{d0,a} - I_{q,a}.(x_{q,a} - x'_{q,a})
\end{aligned} \tag{3.31}$$

$$\begin{aligned}
&T_{E,a}.\tfrac{dE_{fd,a}}{dt} = -(K_{E,a} + S_E(E_{fd,a})).E_{fd,a} + V_{R,a} \\
&T_{A,a}.\tfrac{dV_{R,a}}{dt} = -V_{R,a} + K_{A,a}.R_{f,a} - \\
&\tfrac{K_{A,a}.K_{F,a}}{T_{F,a}}.E_{fd,a} + K_{A,a}.(V_{ref,a} - V_a) \\
&T_{F,a}.\tfrac{dR_{f,a}}{dt} = R_{f,a} + \tfrac{K_{F,a}}{T_{F,a}}.E_{fd,a}
\end{aligned} \tag{3.32}$$

The number of differential and algebraic equations are now reduced by representing each coherent group as a single machine using equations (3.31) and (3.32). As a result, the computation burden of solving these equations in dynamic stability studies can be minimized significantly.

Due to changes in the operating condition of the power system the dynamics of the generators results in different coherent groups. Therefore, the coherency of the generators is affected by the duration, location, type, and magnitude of the disturbance [25]. Thus, coherency based aggregation becomes challenging when it is required to aggregate a very specific and arbitrarily part of the grid. Since the objective of this paper is to aggregate the low voltage networks a main focus will be given to aggregation methods with predefined boundaries and an external subsystem, low voltage levels. For model aggregation applications of a very large model the aggregation can be performed using modal analysis, however, the physical structure will not be preserved.

3.1.2 Dynamic Aggregation Based on Modal Analysis

A model aggregation based on modal analysis is a comprehensive methodology used to build the dynamic equivalence of a large interconnected system described by LTI models. In this approach, the generators in the external system that has no or less impact on the internal system are eliminated based on the modal analysis results i.e. eigenvalues and eigenvectors. Due to the elimination of less observable and less controllable modes, the modal equivalencing approach doesn't preserve the physical characteristics of the external system. Hence, the main objective of modal analysis equivalencing is to preserve the dominant modes of oscillations, in this case, electromechanical modes. The electromechanical, also called poorly damped modes [31], are of interest as they are responsible for the most of the oscillating behavior which dominates the long-term dynamics of the system. This characterizes how fast the response of the external system reaches the steady state. Therefore, modal analysis is used to identify the inter-area modes as well as the modes that are related to the dynamics of the excitation system. The modal decomposition method can be applied either by extracting the time scale components of the state space representation [28, 13, 29, 34, 33, 15] or using pole-zero cancellation of less dominant modes using the frequency response of the system described by its transfer function [40, 9].

3.1.2.1 Model Aggregation Using Transfer Function

Given the linear state space model, the dynamic characteristics of a power system can be revealed using the poles and zeros of the system's transfer function. Clustering technique based on Euclidean distance, also called fuzzy clustering [40], is one way of modal analysis aggregation method which utilizes the system transfer function to group both the poles and zeros of the complete system. Since the transfer function is computed for the complete system, it is difficult to differentiate the poles and zeros that characterize the external subsystem. Therefore, this method can't be used to aggregate only some specific parts of the system and this topic is included in this report to look the possibility of aggregating the external subsystem separately.

To illustrate this aggregation method, a fuzzy clustering technique proposed in [40] is summarized into the following 5 steps.

- **Step 1:** Linearizing the system and formulating the state space equations.
  Assuming an LTI system with configured parameters, the power system can be described using the state space dynamic equations.

$$\begin{aligned} \dot{x} &= Ax + Bu \\ y &= Cx + Du \end{aligned} \tag{3.33}$$

  Where $A \in R^{nxn}$, $B \in R^{nxm}$, $C \in R^{pxn}$ and $D \in R^{pxm}$ are the state, input and output matrices of the power system described by the state, input and output vectors of x , u and y, respectively; n, m and p are the order of the system, number of input and output variables, respectively.

- **Step 2:** Computing the transfer function of the complete power system.
  From the state space representations in equation (3.33) the poles and zeros of the complete system can be computed based on the transfer function of the system which is found to be;

$$G(s) = C.\left(sI - A\right)^{-1}.B + D = \frac{\prod_{i=1}^{n}(s - z_i)}{\prod_{j=1}^{m}(s - z_j)} \tag{3.34}$$

- **Step 3:** Clustering poles and zeros into distinct groups.
  Using the required tolerance, the poles and zeros of the original system from step 2 that characterize less important oscillation modes need to be clustered. Then, the electromechanical modes are required to retain without being clustered and reduced. A method called balanced truncation is presented in [9, 28, 34, 35] on how to find the states corresponding to the small singular values. For a specified tolerance of model aggregation, these states can be truncated without losing the main dynamic behaviors of the system.

- **Step 4:** Formulating the transfer function of the reduced order model
  The reduced order transfer function is then described collectively by poles and zeros from the retained low-frequency oscillations (electromechanical modes) and the

clustered groups. The equivalent poles and zeros of the clustered groups are then obtained by averaging the clustered poles and zeros of the original model. As a result, the new reduced order transfer function is found to be.

$$R^{'}(s) = \frac{\prod_{i=1}^{n'}(s - z_i)}{\prod_{j=1}^{m'}(s - z_j)} \tag{3.35}$$

– **Step 5:** Calculating the gain adjustment factor.

Finally, a correction factor k is determined in order to make the time response of the reduced order model in equation (3.35) compatible with the complete higher order model in equation (3.34). The gain adjustment factor can be calculated by evaluating the steady state conditions of these two models.

$$k = \left.\frac{R^{'}(s)}{G(s)}\right|_{s=0} = \left.\frac{\prod_{i=1}^{n}(s - z_i).\prod_{z=1}^{m'}(s - z_z)}{\prod_{j=1}^{m}(s - z_j).\prod_{p=1}^{n'}(s - z_p)}\right|_{s=0} \tag{3.36}$$

This gain factor is used to adjust the steady state response of the reduced order model and the final reduced order transfer function that preserve the characteristic of the complete system. The final adjusted system transfer function is then described as:

$$R(s) = k.R^{'}(s) = k\frac{\prod_{i=1}^{n'}(s - z_i)}{\prod_{j=1}^{m'}(s - z_j)} \tag{3.37}$$

Finally, the dynamic response of the reduced order model can be determined using the transfer function in equation (3.37).

3.1.2.2 Model aggregation using state-space representation

One of the most commonly used methods utilizing the LTI state space representation in equation (3.33) is singular value decomposition [34, 35, 33]. As it has been studied in [9, 13, 29], this method can be further used for nonlinear systems using projection matrices in balanced truncation. The principle of this technique is mainly based on the controllability and observability Gramians which describes the input-output characteristic of the dynamic system, and modal extraction using Hankel matrices. When the states correspond to a very small or zero Hankel Singular Values (HSV), they are eliminated and the reduced order system remains with most of the input-output behavior of the external system. The modal analysis equivalencing or aggregation procedures using this method are presented in [28, 13, 34, 35, 33, 15] and the general algorithm, considering aggregating LTI system, can be summarized in three steps.

1. **Compute the empirical controllable and observable Gramian matrices.**

   The gramian matrices which describe how the inputs affect the system states and their influence on the output are the important parameters to maintain both the controllability and observability of the system. Assuming the system in equation (3.33) meets the conditions of stability, controllability and observability the corresponding gramian matrices are defined as;

$$\begin{aligned} W_C &= \int_0^\infty e^{At} BB^T . e^{A^T t} dt; \\ W_O &= \int_0^\infty e^{A^T t} C^T C . e^{At} dt \end{aligned} \tag{3.38}$$

   While computing the gramian matrices in equation (3.38) considering a stable system the solution of Lyapunov equations are assumed to exist, [34], which are defined as.

$$\begin{aligned} & A.W_C + W_C.A^T + BB^T = 0 \\ & A^T.W_O + W_O.A + C^T C = 0 \end{aligned} \tag{3.39}$$

2. **Compute the Hankel singular values of the system.**

   For a balanced system, with the same observable and controllable matrices and diagonal of HSV, the state-space realization of calculating the gramian matrices leads to a balanced realization. Then, the diagonal matrix can be calculated as:

$$W_C = W_O = W = diag(\sigma_1, \sigma_2, \sigma_3 ... \sigma_j) \tag{3.40}$$

   The value of each diagonal component is then computed as, [34]

$$\sigma_j = \sqrt{\lambda_j . W_{O,j} . W_{C,j}} \tag{3.41}$$

   Where λ_j denotes the j^{th} eigenvalue.

3. **Truncate the balanced states which have little influence on the input-output of the system.**

   After the computation of diagonal elements in equation (3.40), truncation can be carried out over the small or zero Hankel singular values to reduce the order of the model. Sorting these values, the less important states can be determined meeting the required accuracy of model aggregation.

$$(\sigma_1, \sigma_2, \sigma_3 ... \sigma_k, \sigma_{k+1} ... \sigma_j) \tag{3.42}$$

Sorting the Hankel singular values $\sigma_1 > \sigma_2 > \sigma_3 ... > \sigma_k$ the values σ_{k+1} to σ_j can be truncated, assuming they have less impact to the input-output characteristic of the system.

3.2 Measurement Based Dynamic Aggregation

Data-driven or measurement based order reductions are recently motivated by the availability of Wide-Area Measurement System (WAMS) and instrument facilities, which uses phasor measurements. Due to the GPS-synchronized data recording and export, this method is more efficient to develop dynamic equivalents for the purpose of online assessment, provided that there are enough digital recording devices [4]. The measurement units installed only at selected boundary buses are used to gain insight into the main dynamic impacts of the external subsystems on the study or internal subsystem. Using the direct measurements of the state variables the dynamic aggregation can be performed in the absence of the mathematical models and therefore, a precise knowledge about the model parameters is not required. This makes the dynamic aggregation faster compared to model-based equivalencing techniques which are based on the numerical computation of the mathematical models. However, because of a real-time measurement precision and synchronization problems, aggregation from the direct measurements will not provide efficient equivalent models. In [20], the authors proposed a combined coherency-measurement-modal analysis based aggregation where pilot buses are built by aggregating the voltage and current measurements at the boundary buses following a disturbance in the study area. Then, a modal decomposition method is applied to extract the slow time scale response of these measurements. This combined aggregation method is an efficient way to preserve the properties of specific boundary buses with installed PMU.

The original model is considered to be divided into r non-overlapping coherent areas where each area is characterized by m_k, n_k and b_k unique generator, load and boundary buses, respectively. Each coherent area is then represented by an equivalent generator bus as shown in Figure 3.6. In this case, only the equivalence of one coherent area is presented. For n coherent areas, n similar equivalent generator buses will be connected to the study

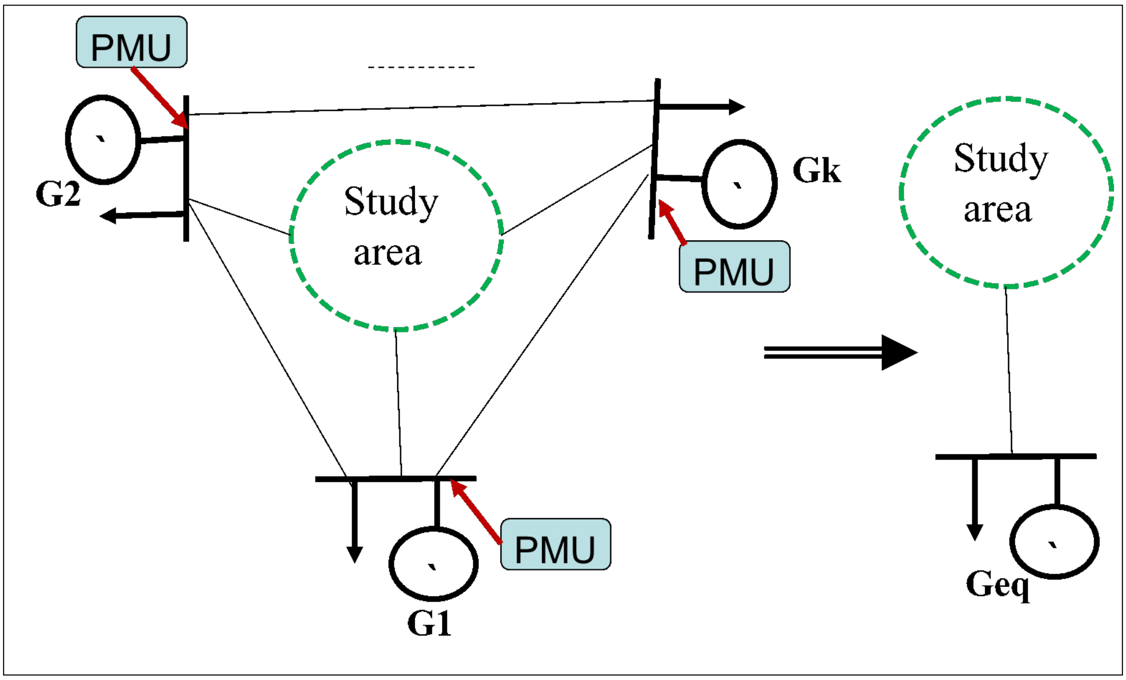


Figure 3.6: Aggregating coherent boundary buses into an equivalent bus

area representing each coherent group. After a disturbance in the study area, the coherency nature of the boundary buses is extracted using the current and voltage measurements of the PMU installed at the boundary buses. In the following section, a measurement directed aggregation method is briefed in four steps based on the proposals in [4, 36, 20].

i) Aggregation of voltage and current measurements

For each coherent group, the equivalent generator bus (G_{eq}) is determined by preserving the complex power of the individual buses.

$$S_{eq} = \sum_{n=1}^{r} S_{Bn} \tag{3.43}$$

Therefore, the total voltage and injected current phasors of the equivalent generator bus can be determined using the measurements from the PMU at every boundary bus and they are defined as:

$$\tilde{I}_k(t) = I_k(t)\measuredangle\theta = \sum_{n=1}^{r} \tilde{I}_{Bn}(t) \tag{3.44}$$

$$\tilde{V}_k(t) = V_k(t)\measuredangle\theta(t) = \frac{\sum_{n=1}^{r} \tilde{V}_{Bn}(t).\tilde{I}^*_{Bn}(t)}{\tilde{I}^*_k(t)} \tag{3.45}$$

Where the superscript $(*)$ denotes the complex conjugate and $\tilde{I}_{Bn}(t)$ is the sum of all current injections to a boundary bus n.

ii) Extraction of the slow time-scale oscillations

Following a disturbance in the study area, the reduced order model is constructed by aggregating the generators that represent the slow dynamics of the coherent area. Since grouping effect of coherent generators eliminates the fast responses, the slow coherency can be determined using modal decomposition by extracting the slow responses of $\tilde{I}_k(t)$ and $\tilde{V}_k(t)$. The same goes for other state variables such as rotor angle of the generators.

$$\tilde{I}_{eq}(t) = \sum_{n=1}^{s} \tilde{I}_k(t) \quad \text{and} \quad \tilde{V}_{eq}(t) = \sum_{n=1}^{s} \tilde{V}_k(t) \Big/ S \tag{3.46}$$

Where S is the number of selected slow coherency components of the voltage and current phasors.

iii) Estimation of generator parameters

Using the current and voltage phasors in equation (3.46) the equivalent generators can be represented in a simplified classical generator model as shown in Figure 3.7. To increase the accuracy of the dynamic aggregation, the equivalent generator bus is represented by a constant induced emf, $E'_{eq} = \tilde{E}'_{eq}\angle\delta_{eq}$, armature resistance and transient reactance as shown in Figure 3.7.

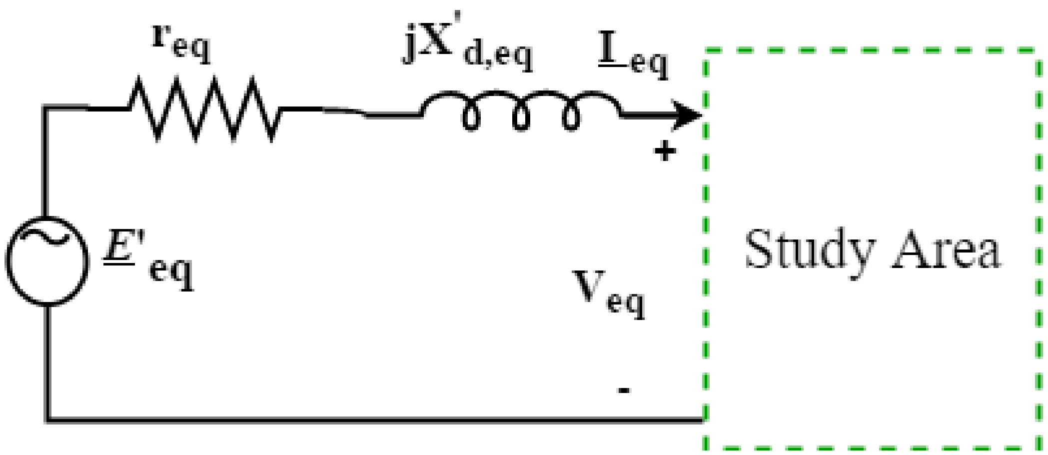


Figure 3.7: Equivalent generator of one coherent group.

With the assumption of a classical equivalent generator model the induced emf is constant over time and therefore using this values together with the aggregated current and voltage phasors the generator impedance can be calculated as:

$$Z_{eq} = r_{eq} + jX'_{d,eq} = \frac{\tilde{E}'_{eq} - \tilde{V}_{eq}}{\tilde{I}_{eq}} \tag{3.47}$$

Applying KVL in the equivalent circuit illustrated in Figure 3.7 the generator induced emf can be defined as:

$$E'_{eq}\angle\delta_{eq}(t) = \tilde{V}_{eq}(t) + (r_{eq} + jX'_{d,eq}).\tilde{I}_{eq}(t) \tag{3.48}$$

The equivalent electrical power is estimated by solving the swing equation or using the electrical parameters calculated above and this can be expressed as:

$$P_{el\_eq} = Re\left\{E'_{eq}\angle\delta_{eq}(t).\tilde{I}_{eq}(t)\right\} \tag{3.49}$$

The remaining inter-area parameters such as mechanical power P_m, inertia M_{eq} and damping ratio D_{eq} are defined by the sum of individual generators in each coherent area.

iv) Estimation of inter-area impedance

Once the current and voltage phasors of the equivalent machine are determined the inter-area admittance can be estimated using the current-voltage equation.

$$\tilde{I}_{eq}(t) = Y_{eq}.\tilde{V}_{eq}(t) \tag{3.50}$$

Where Y_{eq} is the (rxr) admittance matrix of the inter-area connection.

Finally, with the above estimated circuit parameters, the dynamic response of the external subsystem can be represented by the equivalent generator and load connections as shown in Figure 3.7.

Chapter 4

Methodology and Software

4.1 Methodology

As it is discussed in section 3.1.1, coherency measurement of the external subsystem is the main challenge to use coherency based aggregation methods. The aggregation method based on modal analysis doesn't also preserve the structure of the physical model. In other words, the equivalent results are not described by a typical form of differential and algebraic equations of the generators and control systems. Instead, they are represented either by a transfer function or state-space realizations. Following a system disturbance, the dominant modal variables can be retrieved by performing modal analysis and extracting the state variables of the system. Computing the value of these state variables such as rotor angle and terminal voltage, the coherency criteria can be checked using the coherency criteria in equation (3.3). In [31] it has been discussed that the dynamics of the coherent generators is related to the redundancy in the controllability and observability gramians. Therefore, to take the combined advantage, a coherency plus modal analysis method is proposed in this project.

The general procedure of the proposed aggregation method starts by dividing the complete grid network into internal or study and external subsystems, as shown in Figure 4.1. Where the external subsystem is the area of interest for aggregation. This figure is used to illustrate how the complete network is divided into external and study subsystems and to show how coherent groups, assuming the color coded area networks are coherent groups, are grouped after a disturbance in the study subsystem. According to the area of interest, several criteria can be considered to select some parts of the complete system as external subsystems. In this case, the low voltage networks are considered as external parts which are required to be represented by an equivalent aggregated model.

After a system disturbance in the study area, the impact of the external subsystem can be retrieved using the modal analysis results and these results can be grouped based on their impact level in the study area. Finally, applying the coherent aggregation methods presented in section 3.1.1, each coherent group can be represented by an equivalent aggregated model with the DAE in equation (3.31).

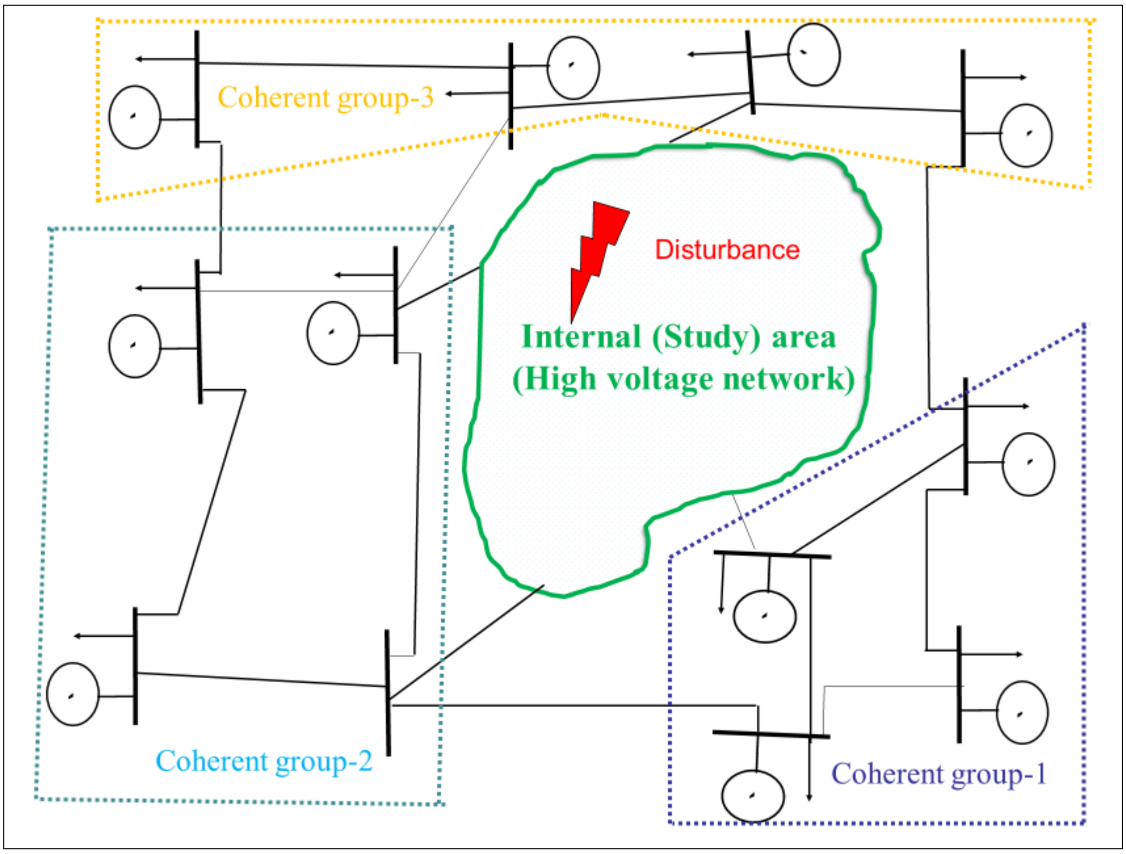


Figure 4.1: Coherency grouping following a system disturbance.

Since the aggregation can be performed for different purposes, as shown in the algorithmic chart, Figure 4.2, it is important to define the performance requirements of the aggregation process. For example; the limits on tie-line power flow among internal and external subsystems, reactive power, voltage and rotor angle dynamics at the boundary buses .etc. Under these performance indices, the selected external area needed to be aggregated and the aggregation process is iterated until all the external subsystem is represented by their corresponding equivalent models, see Figure 4.4. In the aggregation step, the aggregated system parameters need to be calculated according to the coherency of the system components.

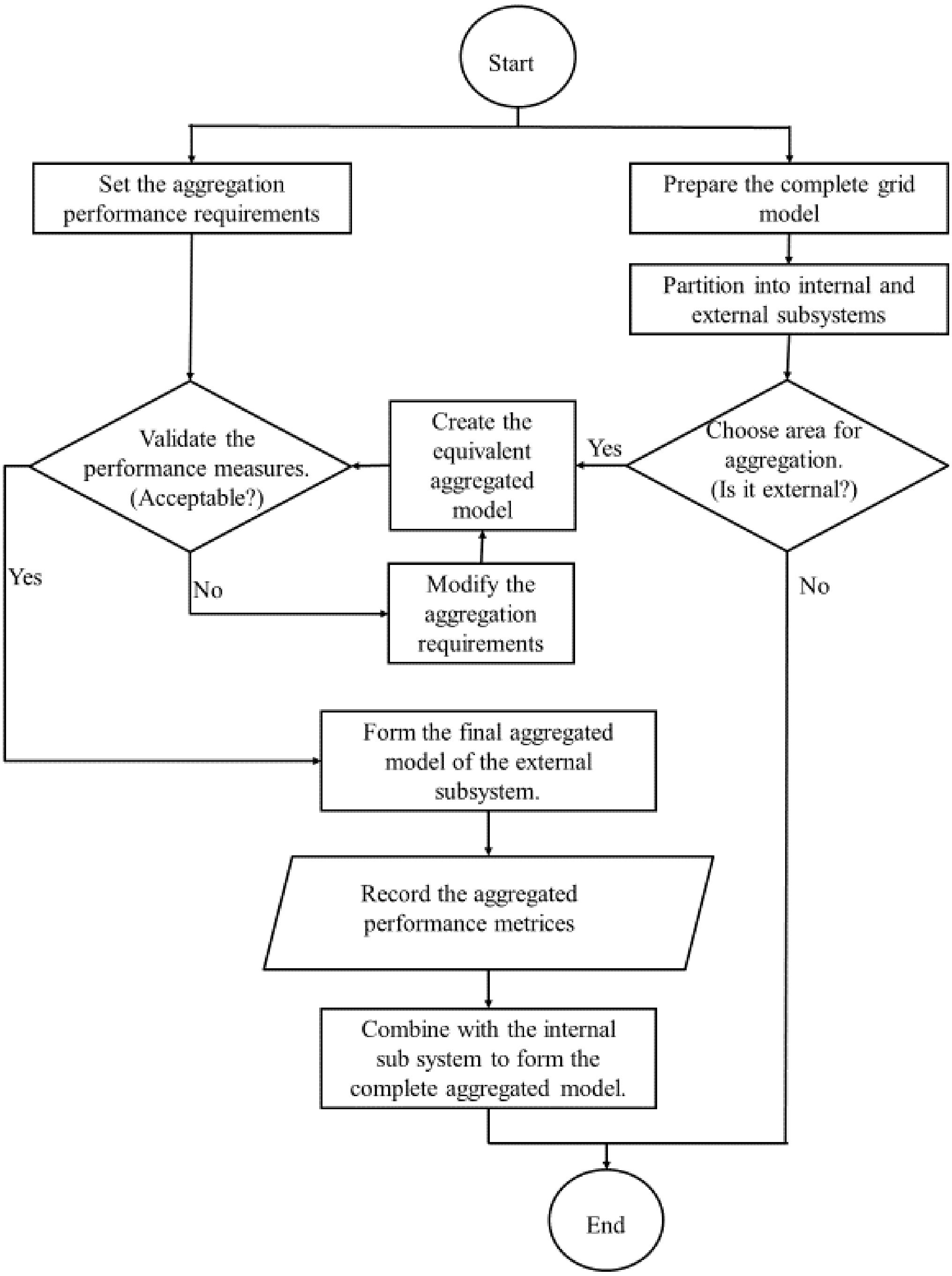


Figure 4.2: Flow chart of the general aggregation methodology.

Finally, the aggregation procedure will be completed by evaluating the performance metrics set to validate the aggregated model at subsystem level and reporting the simulation results to compare with the complete model. To build the equivalent model of the complete system, especially for online security assessment applications, the finalized aggregated model need to be integrated into the study subsystem. Once the aggregation is completed and combined with the internal subsystem, the equivalent model is ready for faster dynamic simulation with the required acceptable tolerances.

4.2 Software

For an efficient power system analysis and market operations, to examine the behavior of the market and reliability of the grid, simulation, and optimization tools are the only solution. For this reason, different power market companies and grid owners use diverse power system analysis software tools to guide their planning and operation studies as well as to make marketing analysis of their grid investment. Therefore, it is important to know the functionalities of these tools and the grid data can exist in several data formats. In this report, a Siemens's commercial software called Power System Simulator for Engineering(PSS®E) is used to test the proposed aggregation methodology in the Norwegian power grid and IEEE 24 bus RTS as case studies.

4.2.1 PSS®E

PSS®E is a widely used software for transmission planning and operations in the design and operation of reliable power grid models. Many power grid owners and industries utilize this tool to study power flow and OPF, pricing and transfer limit analysis, small signal stability analysis, and extended term dynamic simulation. The API routines in this simulation tool allows a subsystem definition to limit the scope of the study area. These definitions could be a bus, area, owner or zonal based subsystems, according to the interest of the user to retrieve the grid data. The power system grid data is further presented as a defined group of buses, machine, plant, branch, load, etc. Therefore, the subsystem data retrieval API allows the user to restrict the elements for which data is returned to the program routines, e.g to filter the network data based on their status (in service or out-of-service), subsystem definition, voltage base values etc, and monitor the system components. This subsystem definition together with Scenario Manager enables the user to organize the files that are used during a study. A different group of subsystem data retrieval functions can be found in chapter 8 of the API manual, [26]. In this report, area-based subsystem definition has been utilized to retrieve and manipulate the load, machine, plant and branch bus data family of the required area to be aggregated.

The aggregation of the case studies has been performed based on power flow solutions as well as dynamic simulation results. To brief how to use this tool, the general procedure to use PSS®E for power system study can be summarized into the following steps.

Step 1: The user need to prepare the working case (*.sav) files with a proper generator and load conversions and power flow solutions which must be solved to an acceptable mismatch level.

Step 2: Once the converted case is ready a stability run can be initiated using this converted case(*.sav) and the dynamic(*.dyr) file. Since dynamic simulations in power system require a good modeling of all the dynamic devices in the network, the user needs to make sure all models are working properly, including user-defined models if there are any. This can be checked by applying an initial condition simulation. Performing this simulation before dynamic simulation will help the user to closely look at the initial value of all variables as a function of the model's constant data and boundary condition in the working case. Ideally, a successful initial condition simulation will print out the message "INITIAL CONDITIONS CHECK O.K." to the screen that shows all the state variables are initialized with the defined boundaries. This will be the base case simulation. Otherwise, it is common to see this message instead "SUSPECT INITIAL CONDITIONS" indicating some errors during setup. Checking each suspect condition becomes a big challenge especially when working on a very large model. However, it is important to note that the main common situations which may cause these suspect initial conditions are specifying model data improperly, exceeding the limit of model variables during initialization or unrealistic gain and time constants.

Step 3: Finally, the user can perform a stability run to study the dynamics of her/his base case.

The general outline to perform stability analysis is:

Algorithm 4.1 General outline of performing dynamic study

Step 1: Apply a disturbance or switching event for the stability study.
Step 2: Run the simulation for time 0 to t= fault clearance time.
Step 3: Clear the fault.
Step 4: Run the simulation again for time t= fault clearance time to t= simulation time, most commonly 10 seconds.

4.2.2 Python

This section presents only a brief introduction to Python programming language and an overview of its interaction with PSS®E. For further study and detailed tutorials, the reader can refer the psspy discussion page[1] . Python is a high-level programming language which is widely used in the field of scientific and numeric computing, software development, image processing, science and education applications and others. As a result of being a high-level programming language, python is a portable language where the users can use their code to run on different kinds of computers with few or no modifications.

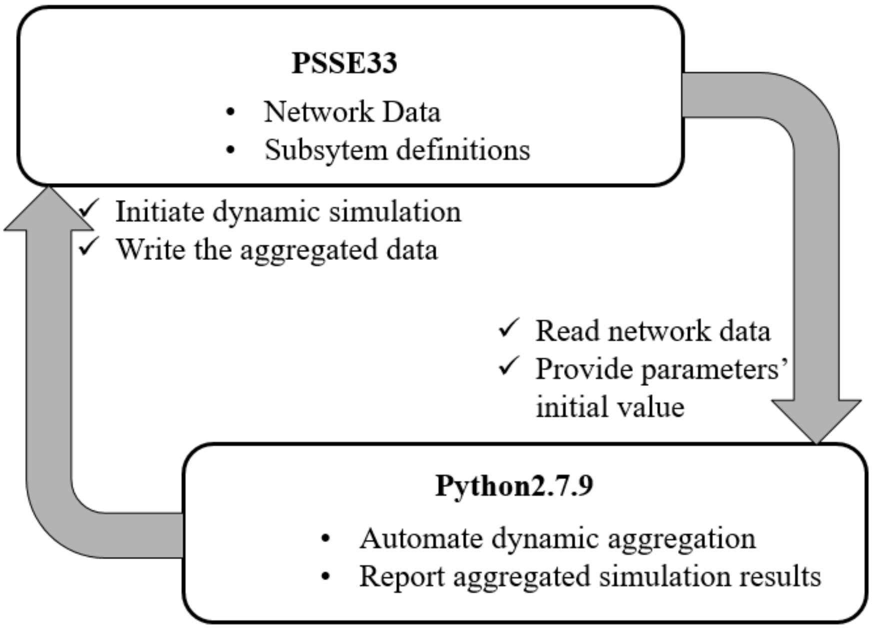


Figure 4.3: Interaction between Python and PSS®E

[1]https://psspy.org/psse-help-forum/questions/

Even though python is a widely used programming language, the main focus in this report will be on its purpose to create user-defined calculation commands, program automation functionalities and its integration with PSS®E. As shown in Figure 4.3, the aggregation automation is achieved through python to trigger a disturbance, modify data, control parameters, retrieve and export data for a graphics data presentation. This helps to improve the efficiency and reduce the simulation time of the dynamic aggregation.
Python comes with basic standard libraries and built-in-functions providing different functionalities on several data types. In addition to the standard library installed with Python, the users can import several other libraries into their program which are currently available on the internet for download. PSS®E installation includes the basic python extension packages that can be imported into user program. Further description of the modules supplied with PSSE can be found in [27, 12].
Some and the most helpful python modules, mainly for this report, and their functions are briefed as follows:

- **redirect:** Provides tools for directing PSS®E output to Python, and vice versa.
- **pssdb:** Provides access to the PSS®E Database API.
- **excelpy:** Provides the interface between python functions and Excel workbooks for data manipulation and report generation.
- **plot2wordw:** Provides the tools to create Word documents from simulation plots.
- **pssexcel:** Allows the python functions to export PSS®E data as well as simulation results into Microsoft Excel spreadsheets.
- **pssplot:** Provides python functions access to PSS®E application program inteface plots.
- **pssarrays:** Provides the python functions to retrieve PSS®E simulation results as array elements.
- **dyntools:** Includes tools for processing channel output files.
- **sliderPy:** Provides python functions to directly manipulate diagram elements in the application program.

A user can further improve and simplify the feature of her/his program automation and simulation result analysis by importing additional python modules, other than modules that are delivered as part of PSS®E GUI, into user programs inside or outside the PSS®E program. **matplotlib.pyplot** is an example of such modules which provides a MATLAB-like plotting framework.

4.3 Program Automation

Program automation in PSS@E provides the mechanism to control a set of program execution using either the response files (batch commands) or with the help of programming languages like IPLAN, Fortran or python other than by direct user interaction. The PSS@E interface is also capable of recording API commands in which the user can save automation files either in python script(*.py) or batch commands (*idv). Because of its excellent transition feature to interact with other programs and processes (e.g Microsoft Excel, Matlab, many power system analysis tools like PSS®E), graphics and data visualization(plotting), database connectivity, and graphical user interface programming Python is considered as an automation tool for this project work.

Most users run their python scripts using the “Run Program Automation File”, by opening the PSS®E program first. Some users simplify this automation using customized macro buttons linked to Python file runs. In both cases, PSS®E does run first, and then the python script is executed. However, due to the unnecessary computation burden, this is not an efficient way of automation when PSS®E is needed for a small portion of the program and the heavy computations are performed in python. For this reason, the program automation and execution of PSS®E are triggered by python run files, not the other way around. More information about running PSS®E from python and not the other way around can be found in a power system engineers’ blog[2].

To accomplish the PSS®E program automation through the python scripts we need to tell python where to look to find the PSS®E library files. This is because Python does not know about PSS®E at all. Therefore, it is necessary to provide the location of PSS®E library files in the beginning of the python script, as shown in Algorithm (4.2). The key words in the

[2]http://www.whit.com.au/blog/2011/07/run-psse-from-python-and-not-other-way/

Algorithm 4.2 Python Script to Interact with PSS®E

```
import os,sys
PSSE_PATH  = r"C:\Program Files\PTI\PSSE33\PSSBIN"
sys.path.append(PSSE_PATH)
os.environ['PATH'] = os.environ['PATH'] + ';' + PSSE_PATH
import redirect
import psspy
```

first line help to create an interface to the functionality that most operating systems (*os*) provide and *sys* contains objects maintained by the interpreter that strongly interact with the python program, in this case, PSS®E. The next two lines contain the exact location where the user has installed the PSS®E program. A python extension module *psspy* will use this path to interact with the programs. This package comes with PSS®E installation to perform power systems simulations directly from Python and without opening PSS®E.

Algorithm 4.3 Python Script to utilize the module pssepath

```
import pssepath
pssepath.add_pssepath()
import psspy
```

Even though many PSS®E users use it, the implementation shown in Algorithm table 4.2 has a few limitations. The main challenge to configure the path this way is, it only works on systems where the PSSBIN folder is located at. Therefore, this script will fail to run if it is shared with power system engineer who is using a different version of PSS®E or running on different window installs (32 or 64 bit). A python module called *pssepath* solves this problem by configuring the path automatically as shown in Algorithm table (4.3). Even it simplifies the code required to set up the python environment for PSS®E interaction. The only thing a user needs to do to use the module pssepath is to copy the python script file *pssepath.py* in the directory where the python automation files exist. Afterwards, they can share their code with anyone and get back to doing productive program automation.
In addition to automatic path configuration, *pssepath* helps the user to check and select the available versions of python as well as PSS®E programs on their computer. For further information about the methods of using *pssepath* the reader can refer to the PSS®E application program interface manual, [26].

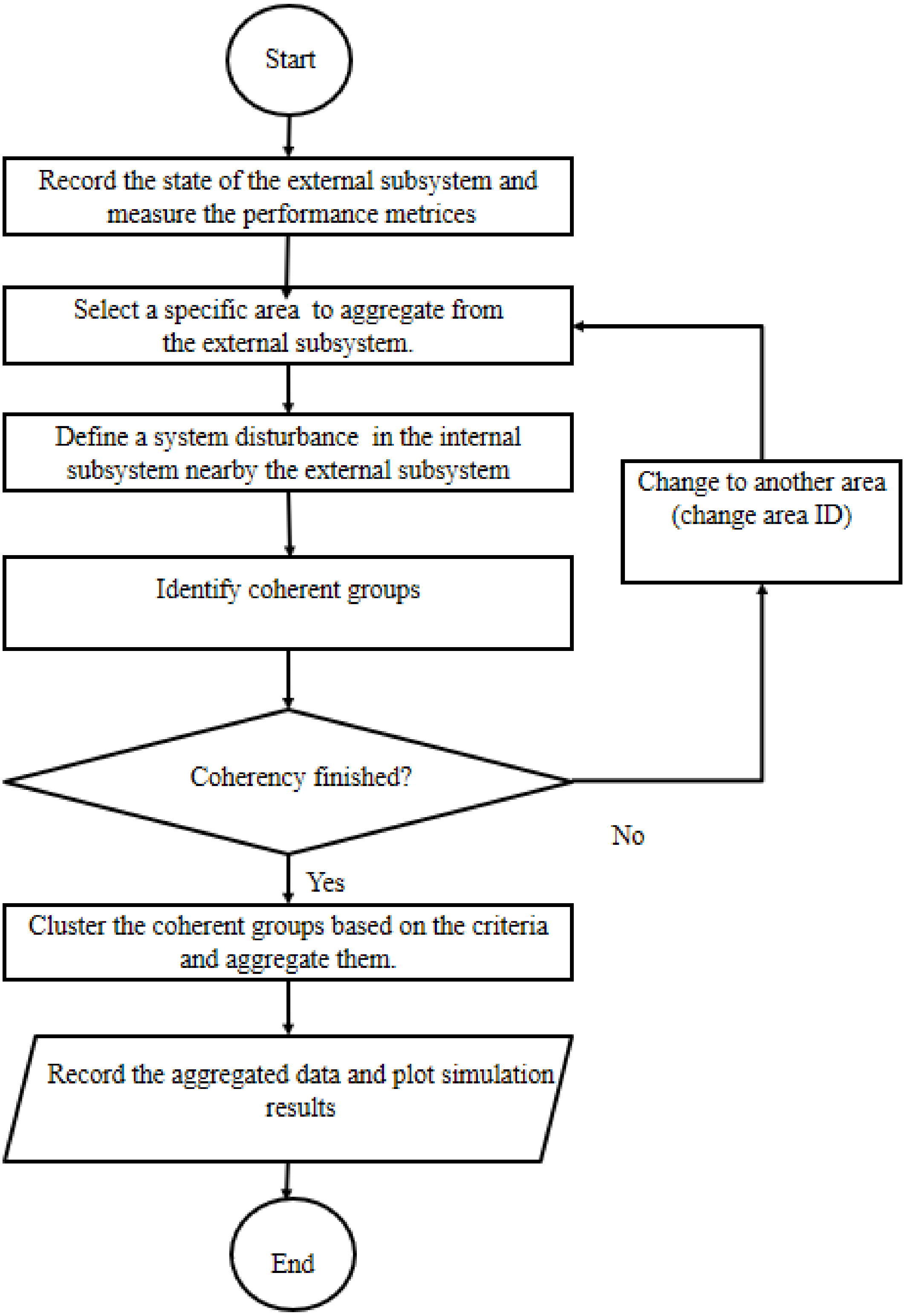


Figure 4.4: Flowchart of the aggregation methodology

The algorithmic steps presented in Figure 4.4 shows that the aggregation automation starts by defining the boundaries of the system and identifying the state of the external subsystem which will be used as measuring indices at the end. As it is mentioned in the equivalent model validation, these indices could be the steady state or/and transient and sub-transient values of the system variables. After the complete system is divided into internal and external subsystems, system disturbance is triggered inside the internal subsystem, closer to the area of interest for equivalencing. For an efficient aggregation process, the disturbance should include possible scenarios that the user want to investigate if the equivalent model will still retain the most important dynamics of the complete model. Following the disturbance, the state of the external subsystem need to be extracted and the coherency system components are measured. The coherency criteria check if the machines in the selected area belong to the same group and the coherency identification continues until the criterion is compared to each machine. Then clusters are formed for each coherent groups and the aggregation is performed for each selected area. Lastly, the aggregated parameters are determined during the aggregation process and the equivalent system parameters are retrieved for reporting and creating the equivalent model.

4.4 System Description

4.4.1 Case Study 1: Norwegian Grid Model

In this report, the Nordic 2015 power grid model is considered as a case study. This model contains a total number of 3080 branches, 2249 buses, 571 generator buses and 620 machines. Since simulation study of such a big model is hard to analyze a subsystem definition is created to target on some specific part of the grid. Therefore, the subsystem definition is performed to focus on the dynamics of the grid with area code 66 containing a base voltage up to 66 kV. This network model is part of the Norwegian grid in the Sør-Trøndelag area which belongs to the NO3 Elspot area in the power market. Therefore, the aggregation technique will be investigated on this targeted area which contains 82 buses, 38 generator buses, and 40 machines. The complete network data of this case study is not presented in this report as it is confidential. The second case study considered in this report is the IEEE RTS which comprises 24 buses, 10 generators, and 38 lines. Two synchronous condensers

(SC) are connected at bus 6 and 14. The single diagram of this case study is shown in Figure 4.5. The generators have a total generation capacity of 3405 MW supplying 2850 MW total real power demand. Further detailed network data of this power system model can be found in the appendix part C. Different scenarios of system disturbances are considered to investigate the impact of the generator dynamics in identifying the coherent machines while determining the aggregated model parameters.

4.4.2 Case Study 2: 24-Bus IEEE Reliability Test System

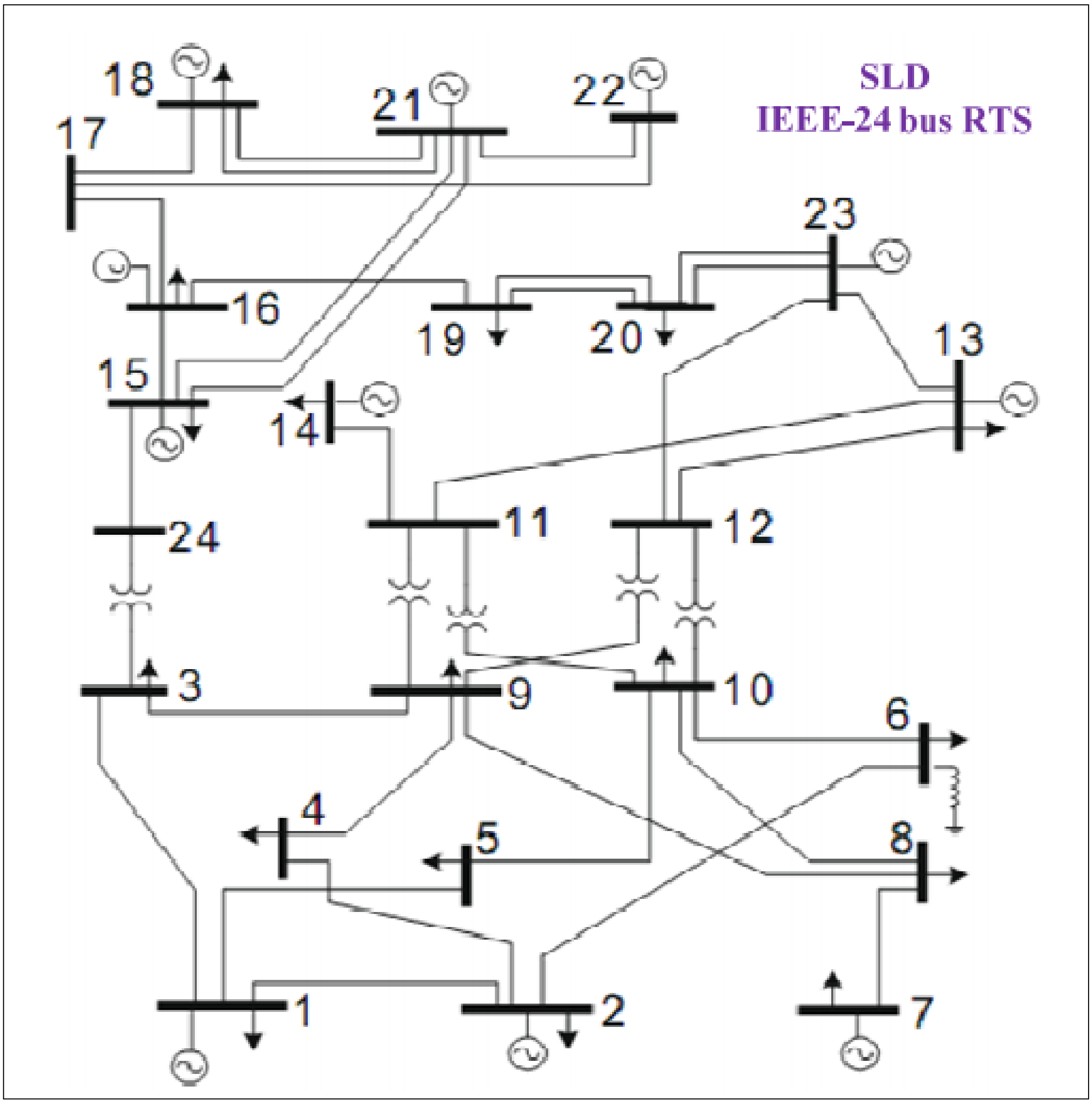


Figure 4.5: Single line diagram of IEEE 24 bus RTS [30]

Chapter 5

Validation of Results and Applications of Grid Aggregation

5.1 Validation of Results

When a model is aggregated, one must be aware of the features and properties that should be retained in the equivalent model. The purpose of aggregation and the model characteristics to preserve highly depend on the application of the equivalent model. To meet the required performance, the equivalent model must therefore accurately represent the original detailed model. This needs to validate the performance of the equivalent model compared to the complete model based on the performance criteria. For large systems, it is also necessary to take into account the trade-off between the cost of generating the equivalent model and meeting its accuracy in preserving the main characteristics. As the model is aggregated too much, the larger deviations are expected between the characteristics of the complete model and the equivalent aggregated one under the same circumstances [37]. Therefore, it is important to keep in mind the limitations of the aggregated model. To mention some challenges of using the aggregated models:

- Retrieving a detailed information about the aggregated network model.
- Handling the primary energy types containing different energy sources at the aggregated level of the model.
- Contingency analysis for networks below the aggregated level.
- Performing forecast and scheduling plan of the individual units.
- Determining the physical interpretation of a combined dynamic impacts.

Therefore, it is important to specify a tolerable error during the aggregation process comparing the obtained results with the complete model. The performance of the aggregated models can be measured in terms of efficiency or/and accuracy. Where efficiency refers to minimizing the size of the network and hence the computation time and memory. Whereas accuracy describes how the required solutions are close to the results of the complete model. Depending on the intended purpose, these solutions can be either result of steady state problems or dynamic stability studies.

5.1.1 Efficiency Measures

As it is mentioned in the problem statement, the main challenge of a dramatic growth in the penetration of distributed generation and cross-country power system interconnections is increasing the grid size. Consequently, in a model aggregation process, the reduction of the computation time and memory requirement to run such a wide network model becomes the main concern. Since the time and memory requirement of computing the models are correlated with the grid size (number of buses, machines, branches, system devices, etc.), the efficiency of the equivalent models can be validated using either of these matrices such as size, computation time or memory requirement.

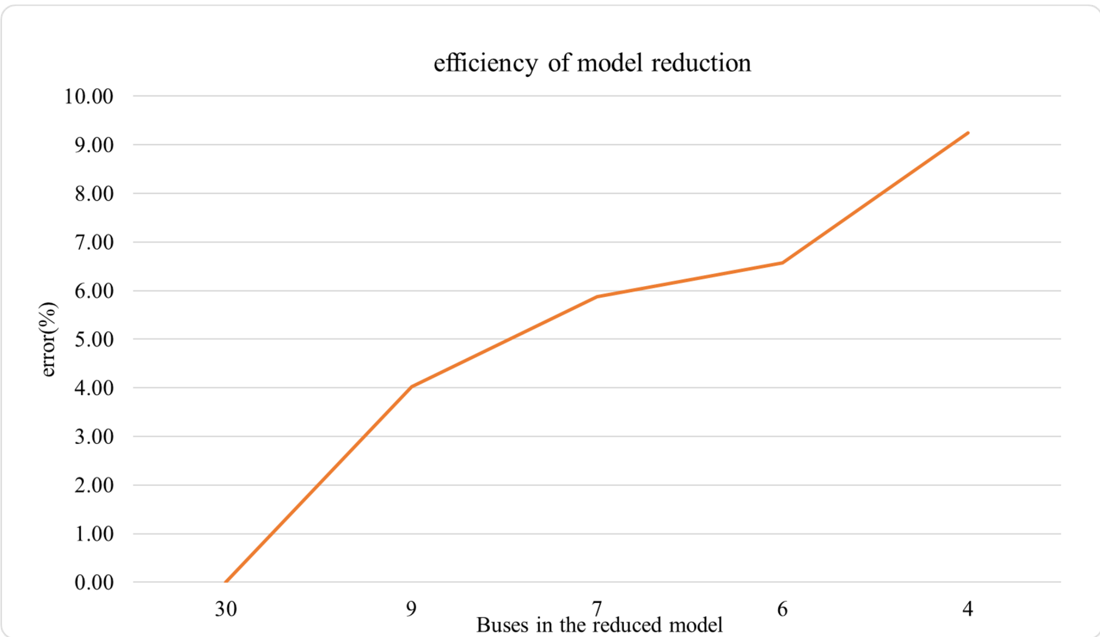


Figure 5.1: Efficiency of Reduced Models

For a power grid model described by the number of buses, the efficiency of the equivalent model can be measured in terms of reducing the number of buses. This is examined using a reduction ratio (RR) defined as:

$$RR(\%) = \frac{F_{no\_bus} - R_{no\_bus}}{F_{no\_bus}}.100 \tag{5.1}$$

Where F_{no_bus} and R_{no_bus} are the number of buses in the full and reduced/aggregated models, respectively.

The reduction of the required CPU computation time is directly related to the reduced order model which is again correlated with the number of buses. In such cases, the efficiency of the aggregated model can be estimated using the grid bus reduction ratio. Ward equivalent aggregation method which is based on Gaussian elimination has been studied in the pre-thesis work and the power flow solutions of the resulting equivalent models, aggregating IEEE 30 bus system, indicates that the errors increases as the model is aggregated more as shown in Figure 5.1. This indicates that the model can't be reduced to less than 9 buses if the errors more than 5% are not tolerated. The detailed analysis of the correlation between the grid size and computation time is beyond the scope of this report.

5.1.2 Accuracy Measures

To ensure that the aggregated model not only meets the reduction of network size and computation time but also the simulation performance requirements, it is necessary to validate the simulation results of the model. Depending on the intended use of the aggregated model, the accuracy of the aggregated model can be validated based on steady state or/and dynamic stability simulation results.

The accuracy of the aggregated models intended for analyzing power flow exchanges, market operation, and power system planning can be validated by comparing the deviation of steady state solutions between the original model and the aggregated one. For a steady state solution of a variable X in aggregating k components of the network, the relative percentage error is defined as [1];

$$Error_R(\%) = \frac{X_f - X_r}{X_f}.100 \tag{5.2}$$

Where X_f and X_r are the simulation results of variable X obtained from the original (full) and reduced order models, respectively. Such performance indices can be helpful to aggregate power grid models used for a power exchange among areas as shown in Figure 5.2.

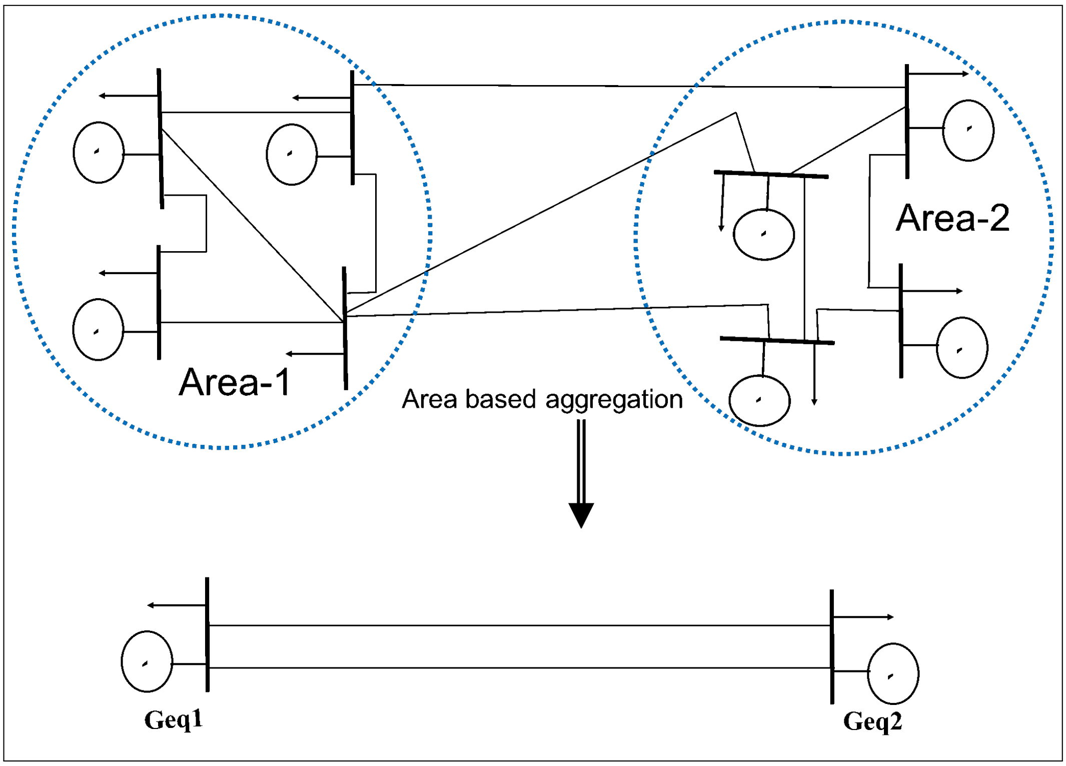


Figure 5.2: Grid aggregation based on geographical area

For example, the power flow among the three areas of the IEEE 300 bus test system has been considered to check if the equivalent models meet the required performance, keep the area transactions as close as possible to the results from the complete model. This was investigated using the power flows as a variable based on equation (5.3). The performance indices of the resulting equivalent model illustrated in Figure 5.3 show that the accuracy also depends on the specific network components that the aggregated grid contains. This is because the aggregation is performed by eliminating the circuit components in the gird, Gaussian elimination.

$$Error_R(\%) = \frac{P_f - P_r}{P_f}.100 \tag{5.3}$$

Where P_f and P_r are the sum of all the tie-line flows between the areas resulting from the full and reduced order models, respectively.

Due to system disturbances, the operating conditions of the power systems are changing frequently and it is important to keep tracing the state of the system accordingly. Therefore, the performance measures discussed earlier, based on steady-state solutions, are not sufficient

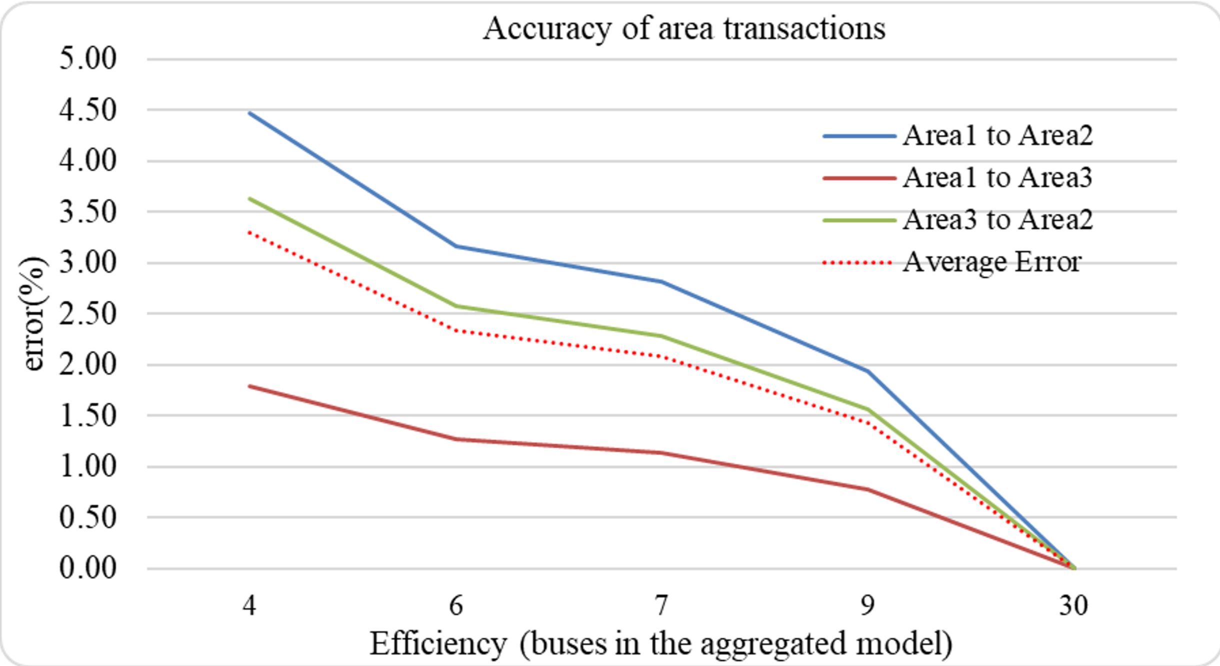


Figure 5.3: Accuracy of reduced models

to validate the accuracy of aggregated models of a system operating under abnormal operating conditions. Then, it is necessary to check the validity of the aggregation process using the dynamic response of the original and equivalent models for the system conditions under which the aggregated model may be used. The dynamic response of the system following a disturbance can be compared either in time or frequency domains.

– **Time-domain simulation:** The main and important question in comparing the equivalent and full models is how to identify the closeness of the simulation results of these models. For systems characterized by state space model this can be measured using a time domain index representing the simulation trajectories $x_r(t)$ and $x_f(t)$ corresponding to the solutions of the aggregated and full models [38], respectively, as shown in Figure 5.4. The performance of the equivalent model is examined using a commonly used metric called Mean Square Error (MSE). For simulation results similar to what is shown in Figure 5.4 the closeness of the resulting time domain response is measured by a time domain index (TD) defined as;

$$TD = \frac{1}{T.\Delta x_f}\sqrt{\int_0^T (x_f(t) - x_r(t))^2 dt} \tag{5.4}$$

Where Δx_f is the peak -to-peak simulation result of a state variable x from the full model and T is the length of the simulation time. The variable x in this case can be rotor angle or terminal voltage of the original as well as the equivalent models.

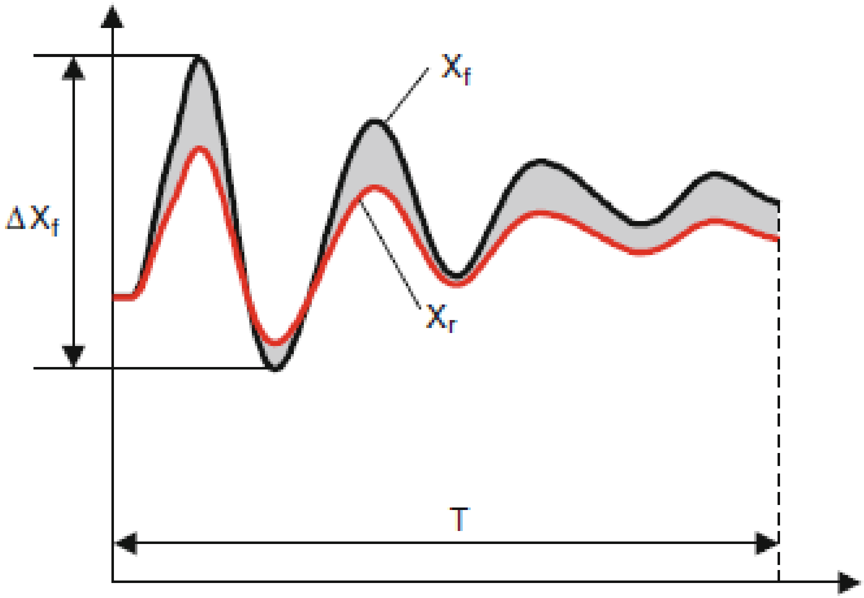


Figure 5.4: Time domain simulation trajectories [6]

– **Frequency response:** The performance of the equivalent aggregated model can be also studied by inspecting the dynamic response in the frequency domain compared to the original model. This approach is mostly used when it is required to design the control system of power grid models in damping power system oscillations [39]. Therefore, in this case, the frequency response is significantly helpful to examine the model order reduction of the generators' excitation system in the complete grid model. The modes of the complete and aggregated model can be then compared to validate the accuracy of the selective aggregation method.

5.2 Applications of Grid Aggregation

In addition to reducing the size of the main grid for transient stability studies, as it is studied in this report, the idea of grid aggregation can be used in a broad power system aspects. Aggregating grid data for market analysis, equivalencing renewable energy sources, mainly wind and solar, power plant controller design and online dynamic security assessment are the most common areas of applications. In which of course the aim of all these aggregations is simplifying the grid network and reducing the computation time.

5.2.1 Market Data Analysis

Most of the power grid models are divided into areas in order to handle large and long-term financial analysis and grid security studies. As a result of market coupling among the Nordic, Baltic, continental Europe, and UK, growing every year as shown in Figure 5.5, the development of mixed production and risk of diverging national market designs grows so fast. The growth of this cross-border grid integration is becoming the main challenging issue regarding an efficient operation of the continental power market.

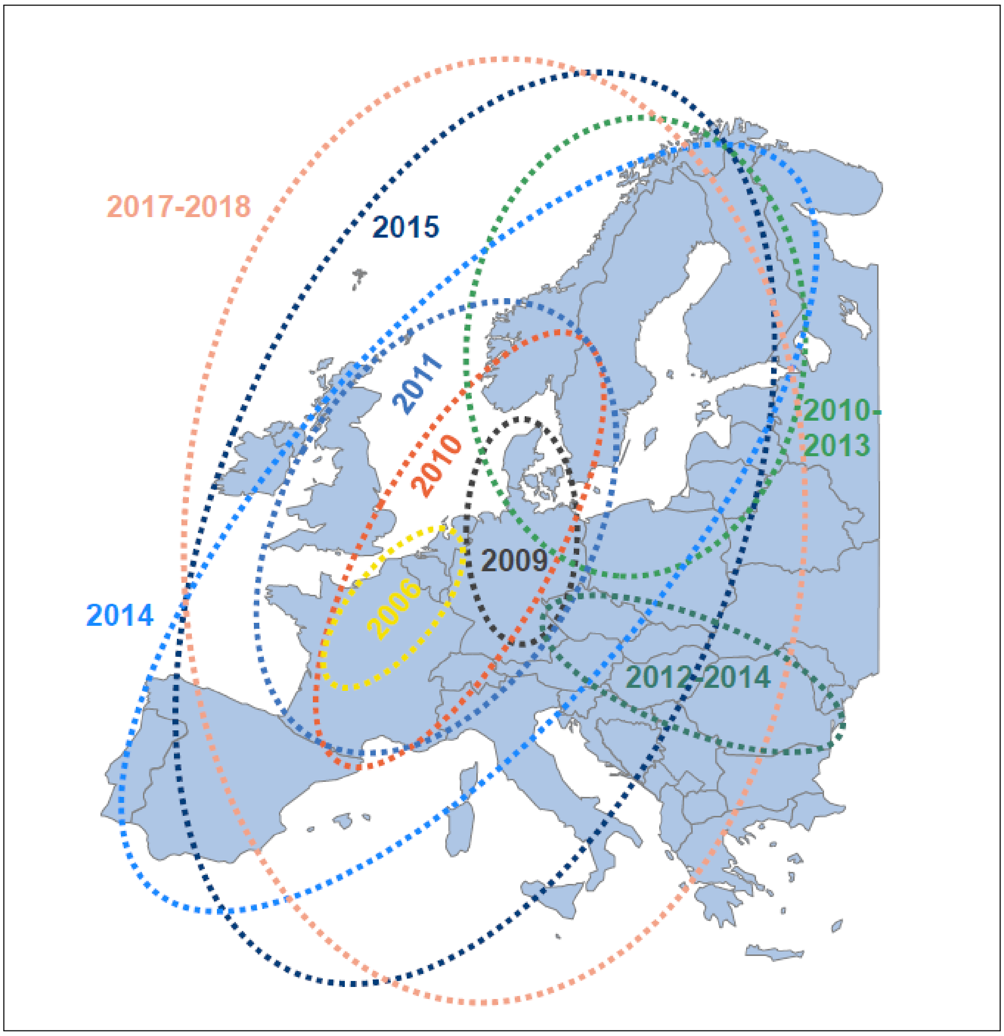


Figure 5.5: Grid Aggregation for European Power Market Analysis [a]

[a]**Source:** https://www.fortum.com

To meet the operational security of the grid TSOs are required to perform transmission capacity calculations by defining a transmission corridor through static and dynamic simulations. Therefore, they determine how much power can be transmitted in any direction through the corridor by avoiding the thermal, voltage and rotor angle stability limitations following the outages and faults in the network. Again, running all the details of such a very large grid data for short-term critical market decisions is impractical.
Therefore, the aggregation of individual grid models can be utilized to analyze the impact of interconnection expansion and energy storage on the future European energy markets. An efficient aggregation will then improve the energy market analysis services such as forecasting prices, fuels, emissions,generation, capacity and load of the energy exchanges.

5.2.2 Aggregation of Wind Power Plants

Nowadays, a very large wind power plants with the size of hundreds of megawatts are integrating into the main grid. In studying the complete grid, mainly while focusing on the high voltage networks, it is not practical to include individual turbines in the simulation studies. Rather, they are represented by a simplified equivalent turbine.

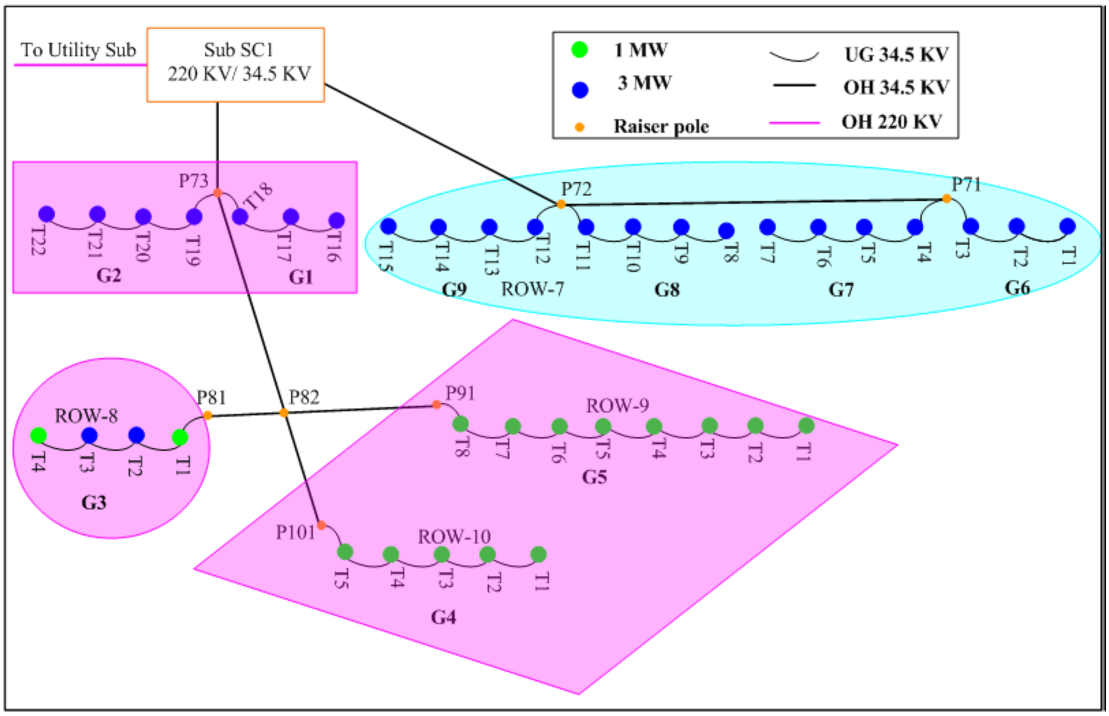


Figure 5.6: Grid Aggregation of wind power plants [19]

Due to the increasing penetration of wind generations, the collective effect of these wind turbines significantly impacts the structure as well as the stability of the main grid. Then, it is required to develop an efficient and accurate equivalent wind farm model. For this purpose, the aggregation methods discussed in this report can be used to simplify power system models that contain expanding wind power plants. Figure 5.6 illustrates how the wind turbines can be aggregated into an equivalent generator models based on their capacity levels, as proposed in [19]. Since the capacity based equivalencing doesn't preserve the system dynamics, coherency based aggregations could be a better solution to simplify such a large wind farms. The reader can find further study in this report, [19], on how the detail system variables such as line impedance and bus voltages are equivalenced while aggregating the wind turbines.

5.2.3 Power Plant Controller Design

In a highly interconnected power system, the smaller parts of the grid are commonly referred as area data instead of individual local components. Such area definitions are given based on the aggregation of individual system parameters in each area. Then these area-based models might be used to develop a low dimensional controller which is applicable for real-time stability study. In such cases, the dynamic response of the aggregated units might be used as an input to design the required system controller which can be utilized for wide-area monitoring and control of the complete grid. A method based on modal extraction has been studied in [5] to estimate the controllers' parameters of a five-area part of the US Western Interconnected power system. This helped the authors to improve the inter-area oscillations of the measurement based model aggregation they have proposed in [4]. They have achieved this by adding the design of a proper controller. A method based on balanced truncation is presented in [17] to design feedback controllers for a global PSS.

5.2.4 Online Dynamic Security Assessment

For a fast and cost-efficient stability study of a particular power system network, it is required to have an accurate model that can respond to real-time situations. However, running the system models and finding the state of system variables takes a long time. Therefore, it is important to have an automated model aggregation that can determine the equivalent parameters of the aggregated network as fast as possible. The resulting equivalent models could be integrated into the study system so that the complete model can be used for online dynamic security assessment. Some research papers like [36, 4, 38, 2, 17] present the possibility of implementing an automated grid aggregation. Most of the authors proposed to utilize a sophisticated phasor measurements and synchronized wide area monitoring tools which make the aggregation technique very expensive.

Chapter 6

Results and Discussion

6.1 Aggregation Based on Steady State Results

To initialize the machines in-service and to represent the dynamic characteristics of the loads in the working case, all generators are transformed into current source model whereas the load models are converted into equivalent constant current and admittance. Therefore, the following assumptions were made in analyzing the steady state power flow solutions.

- Locked Switched shunt adjustments.
- Constant MVA loads of the real power distribution are converted to 60 % constant current, 40 % constant admittance and 0 % constant power.
- Constant MVA loads of the reactive power distributions are also converted to 0 % constant current, 100 % constant admittance and 0 % constant power.

Table 6.1: Voltage level groups of the targeted area

Voltage level group		**1**	**2**	**3**	**4**
Base kV range	Generator Bus	≤ 10	$10 < \text{kV} \leq 15$	$15 < \text{kV} \leq 22$	$22 < \text{kV} \leq 66$
	Load Bus	≤ 15	$15 < \text{kV} \leq 22$	$22 < \text{kV} \leq 66$	-

After a successful steady state power flow solutions of the grid model considered in the first case study, the aggregation of the targeted area was performed considering four voltage levels, as shown in Table 6.1. All the power flow solutions and model aggregations were handled using python automation. The resulting generator and load aggregated power flow results are presented in Table 6.2 - 6.5 and Table 6.6 - 6.8, respectively.

6.1.1 Aggregation of Generators Buses

Since there are many generators in the targeted area, this section presents the aggregated steady state results based on voltage levels of these generators. To preserve the physical characteristics of generators, the machines at each voltage level are aggregated using the coherency criteria discussed in section 3.1.1.1.

1. Generator Aggregation of Voltage Level 1:

Generators with a base voltage up to 10 kV are clustered into the first group and their equivalent power flow results are shown in Table 6.2. In this group, there are two generators in-service connected at buses 57497 and 57486 with zero power generation, which are functioning as reactive compensators. Such information of the machines will be lost when the group of generators in this voltage range are represented by an equivalent generator.

Table 6.2: Generator Aggregation of Voltage Level 1:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	Pgen [MW]
57497	HYNNA-G1G2	7,2	0,936	-1,499	0,0
57516	VESSI-G1	7,5	1,040	1,730	40,0
57506	FUNNA-G1	8,0	1,066	1,809	18,4
57566	NEDAL-G1	8,0	1,000	1,746	24,7
57486	HEGSE-G1	8,5	0,995	0,603	0,0
57498	TEVL-G12	8,8	1,030	1,867	49,5
57536	LITJF-G1	9,5	0,990	1,857	75,0
57436	GRANA-G1	9,8	1,000	1,730	75,0
57056	NEA-G1-	10,0	1,000	-1,476	54,2
57057	NEA-G2-	10,0	1,000	-1,474	55,3
57058	NEA-G3-	10,0	1,057	-1,470	55,7
Group1	**Eq_GenBus1**	**10.0**	**1,010**	**0,493**	**447,8**

The equivalent base voltage would not be accurate to take as an equivalent value for the group as there are many machines with less base voltage. However, this can be improved by adding an idea transformer at the terminal of the equivalent generator. This will help to maintain the actual voltage which is equivalenced well at a maximum deviation of 0.074 pu from the generator with lowest base value connected at bus 57497. Since this one and the generators at a base voltage of 10 kV are oscillating against the rest generators, the equivalent generator angle is not equivalenced well. This is because the aggregation is performed based on base kV voltage levels of the generators and the values are determined using mean value estimation without considering the generator response.

2. Generator Aggregation of Voltage Level 2:

For the second voltage level group, the base voltage is represented very well as all generators except generator at bus 57096 have the same base voltage. Most of the machines also swing coherently except the generator at bus 57059 which swings against the other machines. Therefore, the power flow results in Table 6.3 shows that this group is equivalenced more accurately than the generators in the first group. Of course, the characteristic of the generator at bus 57496 might not be preserved very well in the equivalent generator as it has smaller rotor angle than the equivalent generator.

Table 6.3: Generator Aggregation of Voltage Level 2:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	Pgen [MW]
57096	SLIND	10,5	0,960	1,746	18,9
57059	NEA-TYA	11,0	0,971	-1,517	29,7
57386	N.NEA-G1	11,0	0,990	1,760	60,7
57476	MERAK-G1	11,0	0,880	1,841	57,8
57477	MERAK-G2	11,0	0,900	1,843	26,2
57496	GRESS-G1	11,0	0,950	0,668	18,4
57526	BRATT-G1	11,0	0,980	1,796	33,3
57527	BRATT-G2	11,0	0,980	1,795	33,0
57546	ULSET-G1	11,0	0,990	1,859	35,0
Group2	**Eq_GenBus2**	**11,0**	**0,956**	**1,310**	**313,0**

3. Generator Aggregation of Voltage Level 3:

Similar to the generator groups in the second voltage level, most of the generators in this voltage level are at the same voltage level of 22 kV. As a result, the equivalent generator represents the majority of the generators in this voltage level. The terminal voltage of these generators is also represented by 1.025 pu which is likely similar to the value of each machine. Again the information about the function of the generator connected to bus 57108 which is working as a compensator can't be preserved after the machines in this group are replaced by an aggregated model.

Table 6.4: Generator Aggregation of Voltage Level 3:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	Pgen [MW]
57108	VER-17A	17,0	0,981	1,568	0,0
57445	SOA-22-	20,0	1,111	0,861	36,2
57120	YVIKNA-VP	22,0	1,000	1,438	29,0
57128	HUND-VIND22	22,0	1,020	1,367	4,0
57129	BESS-VIND22	22,0	1,020	1,383	17,0
57407	HITR-VIND22	22,0	1,021	1,013	29,5
Group3	**Eq_GenBus3**	**22,0**	**1,025**	**1,272**	**115,7**

4. Generator Aggregation of Voltage Level 4:

Extracting the generators in this voltage range gives in-service generators containing only a base voltage of 66 kV. As a result, the equivalent generator perfectly represents the base voltage of individual generators.

Table 6.5: Generator Aggregation of Voltage Level 4:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	Pgen [MW]
56544	AGDENES	66,0	1,000	0,824	20,0
57034	KLEBU66	66,0	0,980	0,981	176,0
57044	STRIND66	66,0	0,980	0,955	32,0
57054	NEA66-	66,0	1,019	1,095	4,0
57114	OGNDAL66	66,0	0,970	1,194	130,0
57116	MOSVI-G1	66,0	1,000	1,528	35,5
57124	NAMSOS66	66,0	1,000	1,310	71,0
57127	SALSBR66	66,0	1,020	1,350	10,0
57424	ORKDAL66	66,0	0,987	0,980	40,0
57428	SALVESEN	66,0	1,000	1,003	3,0
57456	MAELAFOS	66,0	1,000	1,046	3,0
57528	SVORKMO	66,0	1,000	1,077	40,0
Group4	**Eq_GenBus4**	**66,0**	**0,996**	**1,112**	**564,5**

As shown in Table 6.5, the actual terminal voltage is also equivaleced to 0.996 pu with a maximum deviation of 0.026 pu from the generator connected to bus 56544. The power generation of these generators in this voltage level varies between 3 MW and 176 MW. All the real power generations from 12 machines are therefore represented by an equivalent unit supplying 564.5 MW.

6.1.2 Aggregation of Load Buses

In this section, the aggregation of power flow results for the loads connected at a base voltage up to 66 kV will be reviewed. To check if the loads are converted according to the defined constant current (60 %) and constant admittance (40 %) ratios, the power flow results are mainly focused on real power distributions and their equivalent aggregated values. The voltage levels are grouped into three ranges, as shown in Table 6.1, where the first group contains both level one and level two defined for the generator groups.

1. Load Aggregation of Voltage Level 1:

This group contains only three small load buses in which two of them have reactive power distribution. Therefore, these loads are represented by an equivalent real power distribution of 0,966 MW of constant current and 0,594 MW of constant admittance values from bus 57056. Since the loads will be added to the generator buses aggregated in section 6.1.1, the base voltage, actual bus voltage and voltage angles will be taken from the generator aggregation in voltage level 2.

Table 6.6: Load Aggregation of Voltage Level 1:

Bus	**Bus_Name**	**Base [kV]**	**Vact**	**δ [rad]**	**ILd**	**YLd**
57497	HYNNA-G1G2	7,2	0,925	-1,500	0,000	0,000
57056	NEA-G1-	10,0	0,990	-1,476	0,966	0,594
57496	GRESS-G1	11,0	0,943	0,668	0,000	0,000
Group1	**Eq_LoadBus1**	**11,0**	**0,953**	**-0,769**	**0,966**	**0,594**

[0] where ILd and YLd are the actual in-service constant current load and constant admittance load given in MW, respectively.

2. Load aggregation of Voltage Level 2:

The power flow aggregation results presented in Table 6.7 shows that the load buses in the range of 15 kV to 22 kV, 18 load buses, can be represented by a real power distribution of 166 MW constant current and 124 MW constant admittance. The base voltage of the equivalent load bus is again taken to be 22 kV even though almost all the buses are at 20 kV. This is because the equivalent load is going to be connected to the equivalent generator bus developed from the third voltage level of generator buses shown in Table 6.4.

Table 6.7: Load Aggregation of Voltage Level 2:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	ILd	YLd
50028	KKI-THA1	20	1,006	1,404	25,810	16,676
50029	KKI-THA2	20	1,068	1,453	14,343	13,592
50041	KKI-HOLL	20	1,036	0,835	62,225	50,923
56545	AGDENES	20	1,028	0,800	2,244	1,410
56546	AGD-TERB	20	1,023	0,812	2,236	1,412
57075	BUAS	20	1,055	0,953	7,984	5,594
57085	HONSTAD	20	1,064	0,934	10,637	6,984
57095	SELBU	20	1,062	1,033	10,090	6,726
57395	SNILLFJO	20	0,894	1,333	4,074	2,073
57396	SNILLFJO	20	1,013	-1,673	0,000	0,000
57399	HEMNE22A	20	0,984	0,839	6,057	3,706
57445	SOA-22-	20	1,048	0,854	2,830	2,517
57457	EIDUM22A	20	1,068	1,054	8,589	5,657
57475	MERAKER22	20	1,052	1,201	2,977	2,202
57485	HEGSETF-22-	20	1,115	1,126	0,000	0,000
57505	FUNNA22	20	1,062	1,274	0,000	0,000
57525	BRATTSET	20	1,053	1,107	6,262	4,073
57129	BESS-VIND22	22	1,038	1,280	0,000	0,000
Group2	**Eq_LoadBus2**	**22**	**1,037**	**0,923**	**166,358**	**123,544**

3. Load Aggregation of Voltage Level 3:

The power flow results of the equivalent load bus for the last voltage level are aggregated as shown in Table 6.8. This contains the aggregated result of all 66 kV load buses represented by an equivalent 800 MW constant current and 540 MW constant admittance real power distributions. This aggregated load will be added to the equivalent generator bus equivalenced as shown in Table 6.5. By doing this, combining the equivalent load and generator buses, there will be 0.083 rad and 0.039 PU deviations in voltage angle and voltage magnitude, respectively. However, this will help to simplify the grid model by adding load and generator buses and at the same time analyze the interdependence of the steady state results for both types of buses.

Table 6.8: Load Aggregation of Voltage Level 3:

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	ILd	YLd
50038	KKI-EXOL	66	0,963	0,976	4,097	2,665
50060	IND-SKOG	66	0,977	1,059	76,956	50,767
56544	AGDENES	66	0,934	0,811	39,782	26,887
57034	KLEBU66	66	0,966	0,979	171,456	117,102
57044	STRIND66	66	0,962	0,952	194,441	127,531
57054	NEA66-	66	1,010	1,095	5,012	4,700
57104	VERDAL66A	66	0,977	1,059	68,077	44,946
57114	OGNDAL66	66	0,965	1,193	86,574	63,776
57124	NAMSOS66	66	0,997	1,280	36,477	25,214
57394	SNILFJ66	66	0,769	0,833	20,754	10,881
57424	ORKDAL66	66	0,963	0,976	57,360	39,012
57454	EIDUM66	66	0,968	1,010	32,001	21,086
57524	BRATTSET	66	0,989	1,150	8,370	5,767
Group3	**Eq_LoadBus3**	**66**	**0,957**	**1,029**	**801,356**	**540,128**

The aggregated power flow results of the complete targeted area, which contains 82 buses and 38 generators, can be summarized as shown in Table 6.9, note that the values of Pgen, ILd and YLd are given in MW. Since all the four generator buses are at different voltage levels it is necessary to include an ideal transformer between them while developing the aggregated network diagram of the targeted area as shown in Figure 6.1. With more loss of detailed grid information, these results can be aggregated further to represent the external subsystem by a single generator bus with 1440 MW generation and 1633 MW consumption.

Table 6.9: Aggregated power flow results of targeted area up to 66 kV

Bus	Bus_Name	Base [kV]	Vact	δ [rad]	Pgen	ILd	YLd
Eq1	Eq_GenBus1	10,0	1,010	0,493	447,8	0,000	0,000
Eq2	Eq_GenBus2	11,0	0,956	1,310	313,0	0,966	0,594
Eq3	Eq_GenBus3	22,0	1,025	1,272	115,7	166,358	123,544
Eq4	Eq_GenBus4	66,0	0,996	1,112	564,5	801,356	540,128
Area66	**Eq_Gen**	**66,0**	**0,997**	**1,046**	**1441,0**	**968,680**	**664,266**

Finally, the complete external area is represented by a 4 bus system network as shown in Figure 6.1. The power flow results of the external subsystem, area 66 containing voltage level less than 66 kV, show that it is a consumption area getting 192 MW from the rest of the system, as NO3 has more load than generation. To represent this power flow the equivalent model is connected to the internal subsystem through an ideal transformer placed at equivalent bus 4 with a base voltage of 66 kV.

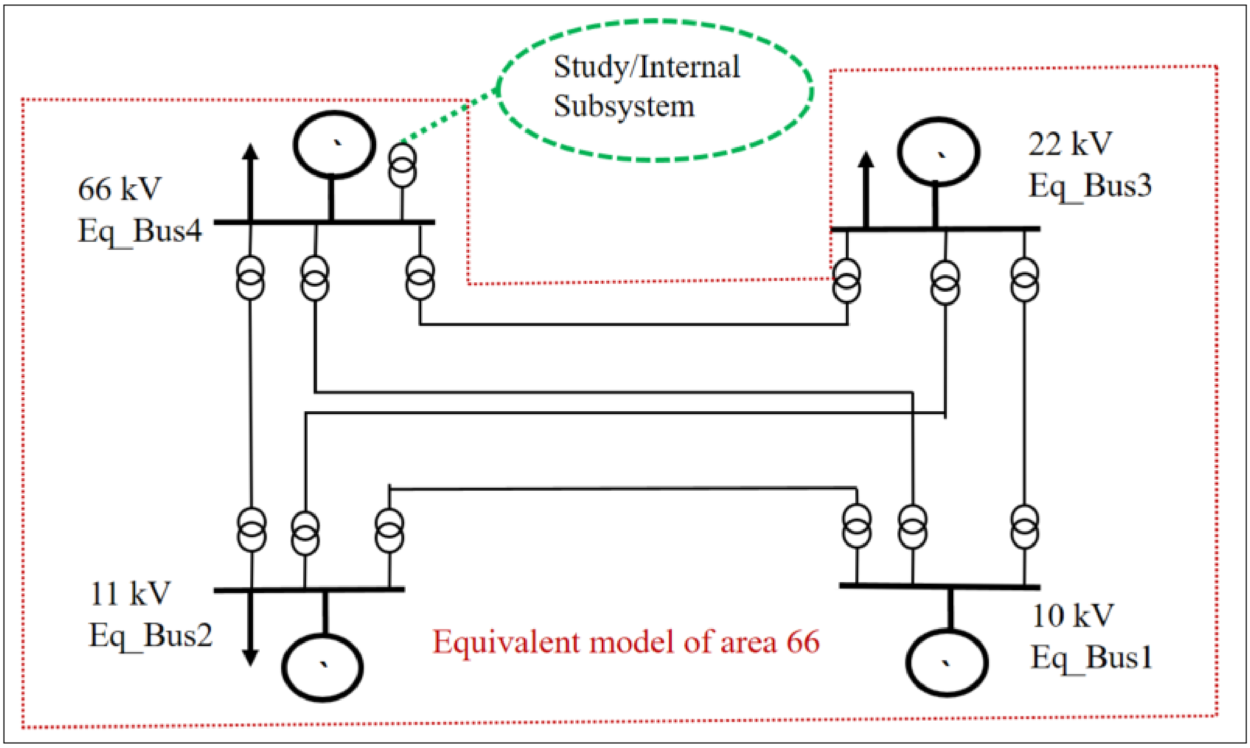


Figure 6.1: Single line diagram of the equivalent model

6.2 Aggregation Based on Dynamic Results

The equivalent aggregated results discussed in section 6.1, aggregations based on steady-state values and voltage levels, show that some important information about the machine's response is lost when aggregation is performed without taking into account the dynamic response of the machines. Therefore, the aggregation results need to be improved by including the dynamic response of the model to be aggregated so that the equivalent models can be used for stability study. Since generator dynamics are the most influential in the overall system dynamic response, it is important to use the dynamic parameters for all generators under consideration. For a very large grid model, like the Norwegian grid in this case, it is difficult to find the complete machine's dynamic parameters. In such cases, the generators located far from the study area can be replaced by equivalent loads, for example, this can be achieved using GNETing (net generation with load) for a power system models working in PSSE. Unfortunately, it was difficult to handle this problem for the first case study of this report. This is because the user-defined models that contain the generator and SVC models of the targeted area, the Norwegian grid with area code 66, were not working properly and it is difficult to fix the parameters of each component the model consists. To analyze the effect of system disturbance in model aggregation the IEEE 24 bus reliability test system has been used as a second case study. As it is mentioned in chapter 3, in many kinds of literature it has been studied that the dynamic stability depends on the generator loading, location, and type of disturbance as well as clearing time of the disturbance. This will affect the coherency identification of the aggregation process. In the next section, some of these scenarios have been considered to investigate the sensitivity of machine's dynamics and their impact in aggregating the external grid model.

6.2.1 Impact of System Disturbance

To investigate the generators' response a three-phase fault with zero impedance is initiated at bus 11 of the IEEE 24 RTS. The fault is cleared after 0,25 seconds and following this disturbance coherent generators are determined based on their rotor angle response.

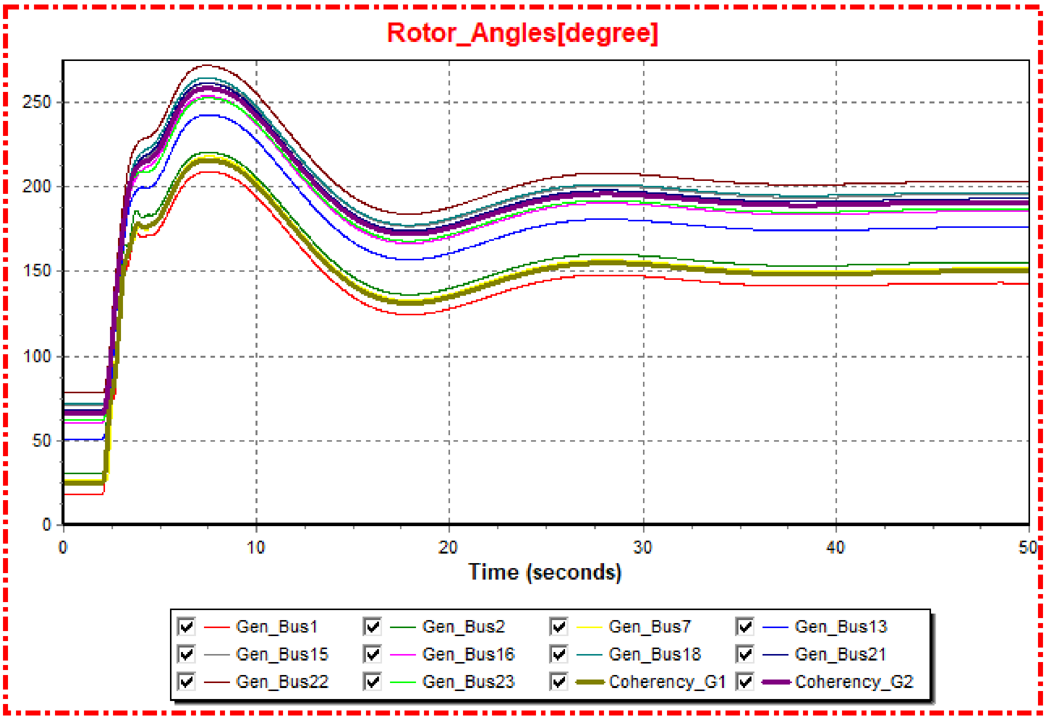


Figure 6.2: Rotor angle responses following 3-phase fault

The rotor angle responses show in Figure 6.2 indicate that all generators are accelerating in the same direction. But generators at bus 1, 2, and 7 are rotating as a coherent group while the rest generators form another coherent group.

6.2.1.1 Aggregation of Generator Buses

As a result of the generator dynamics, the coherency of the generators in the external subsystem are identified using their rotor angle response. Then, each coherent group is represented by an equivalent response called Coherency_G1 and Coherency_G2. The first group consists generators connected at bus 1, 2 and 7 and the second one is the equivalent response of the rest 8 generators. The other generator and load parameters of the equivalent models are therefore determined using the coherency based aggregation methodology discussed in 3.1.1.

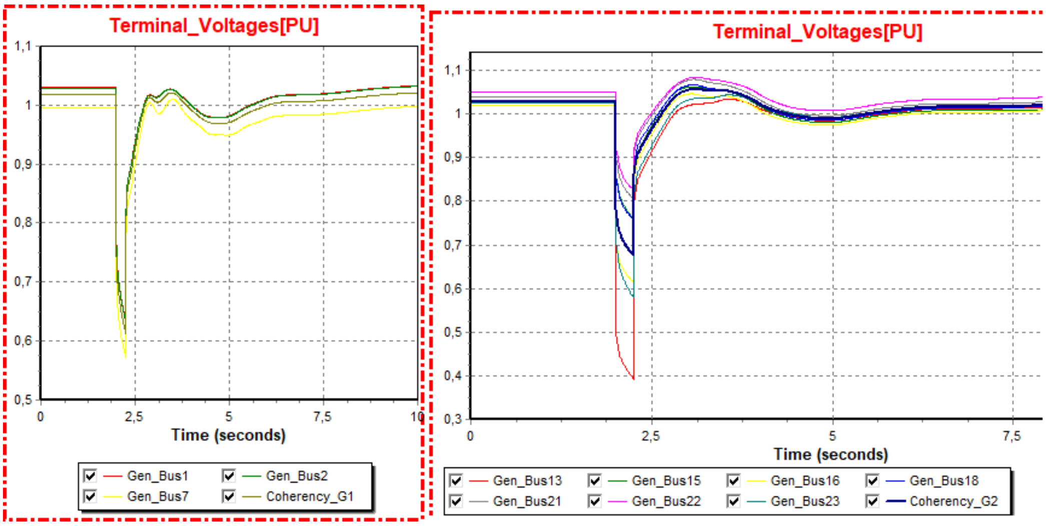


Figure 6.3: Aggregation of generator terminal voltages

The aggregated generator terminal voltages are shown in Figure 6.3 and this indicates that the deep voltage dynamics at generator bus 13, which is at a lower voltage as it is closer to the faulted bus, is missed in the equivalent terminal voltage. As a result, it is important to note the limitation of using equivalent parameters for a detail stability study.

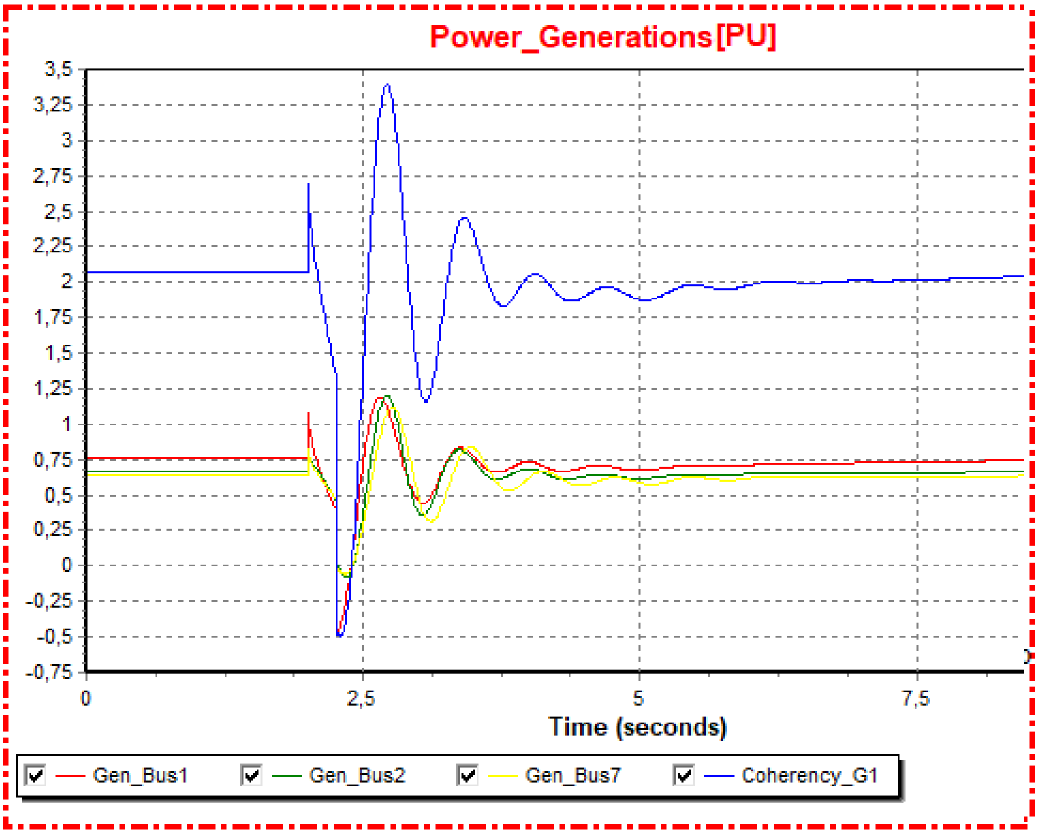


Figure 6.4: Aggregated power generations of coherent group 1

The power generation of each coherent group are also aggregated by adding the generation of each generator in the group and the results of coherent group 1 and 2 are presented in Figure 6.4 and Figure 6.4, respectively. Since all the power generation of the coherent generators are added together the equivalent result will perfectly represent the dynamics of the corresponding coherent group unless there is generation loss.

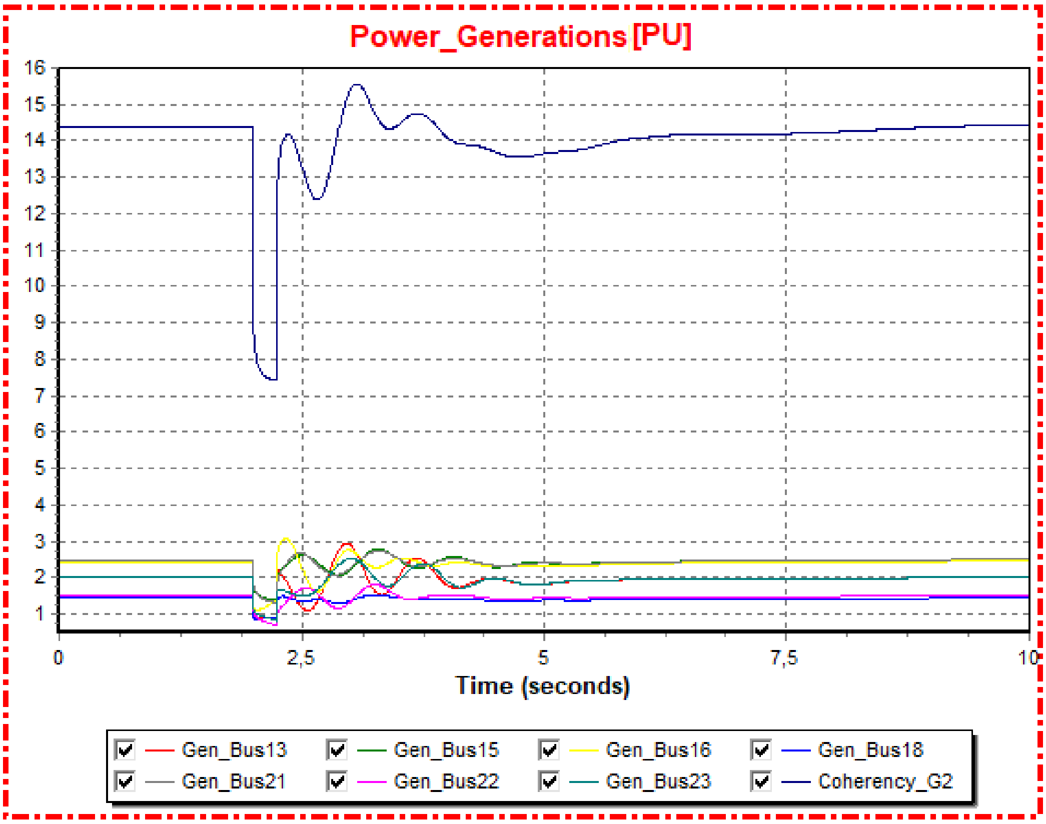


Figure 6.5: Power generations of coherent group 2

6.2.1.2 Aggregation of Load Buses

In determining the aggregated bus voltages, the generator terminal voltages can be taken as bus voltages in a case where the transformer and armature voltage drops are ignored. The results presented in Figures 6.4 and 6.5 indicate that the dynamics of the bus voltages are similar to the generator terminal voltages shown in Figure 6.3. Then, again it is impossible to find the detail dynamic results of the faulted bus from the equivalent aggregated model which are determined based on average values, as shown in Figure 6.7.

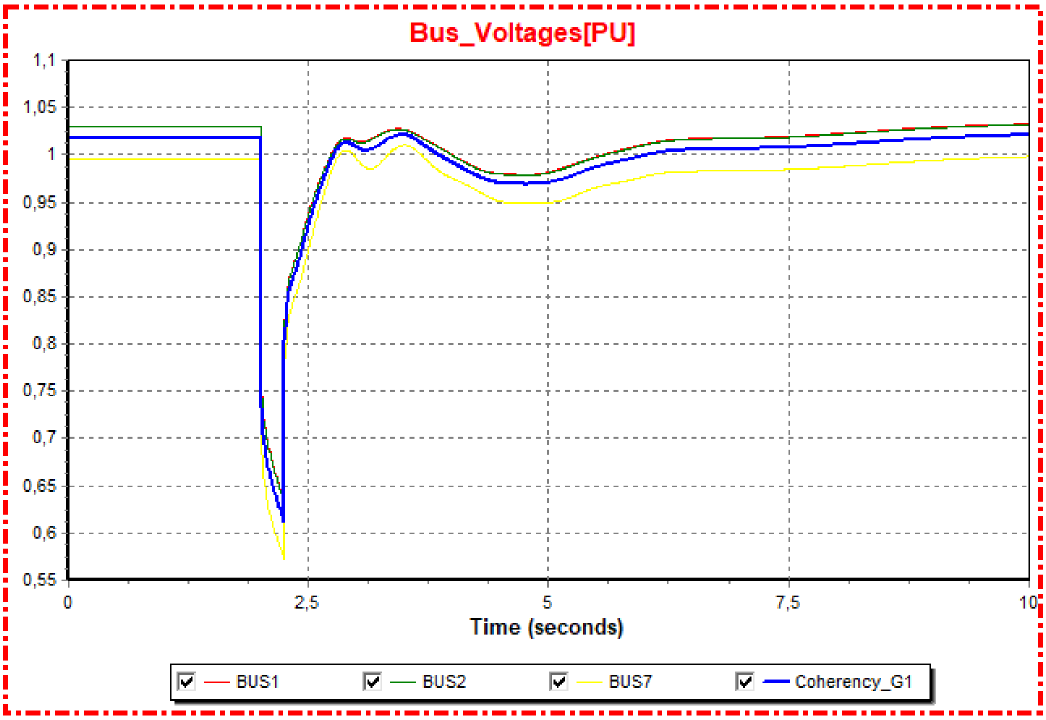


Figure 6.6: Bus voltages of coherent group 1

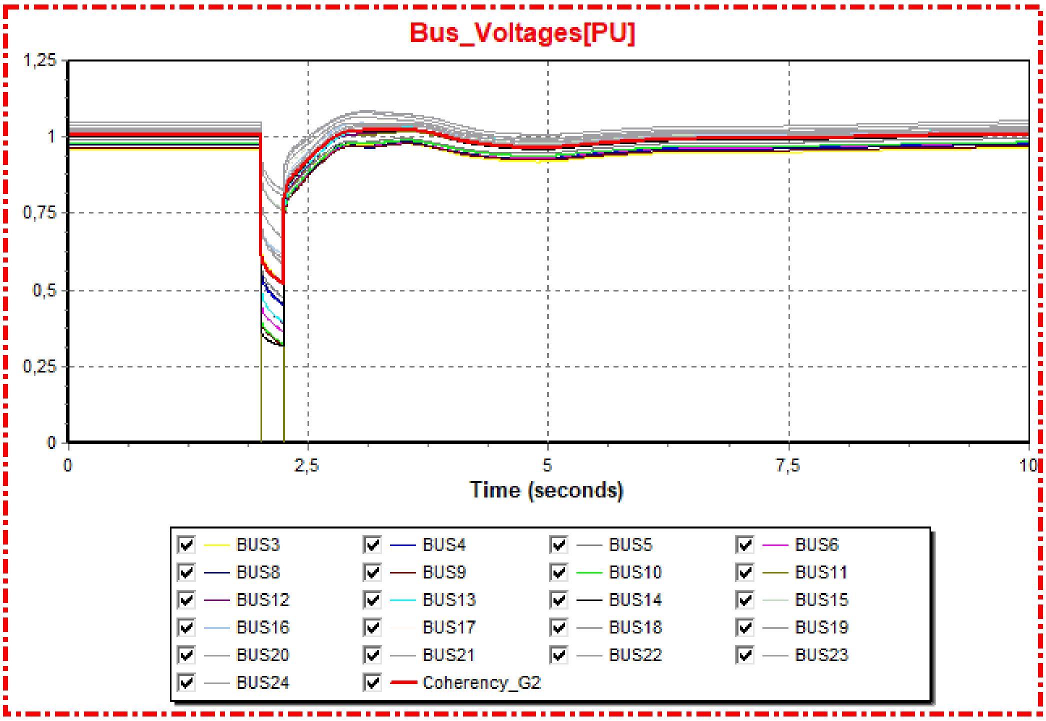


Figure 6.7: Bus voltages of coherent group 2

Once the coherent machines are identified, both the active and reactive loads in the generator bus can be aggregated in a similar way as the power generations. The aggregation of the active and reactive power of the load buses has been studied in this report. Since they have similar dynamics, only the active powers are presented below and for further results on the aggregated reactive power aggregations, the reader can refer to the appendix part A.2. These reactive power dynamic results follow the voltage dynamics as they should and the equivalent active power of each coherent group is shown in Figures 6.8 and 6.9 .

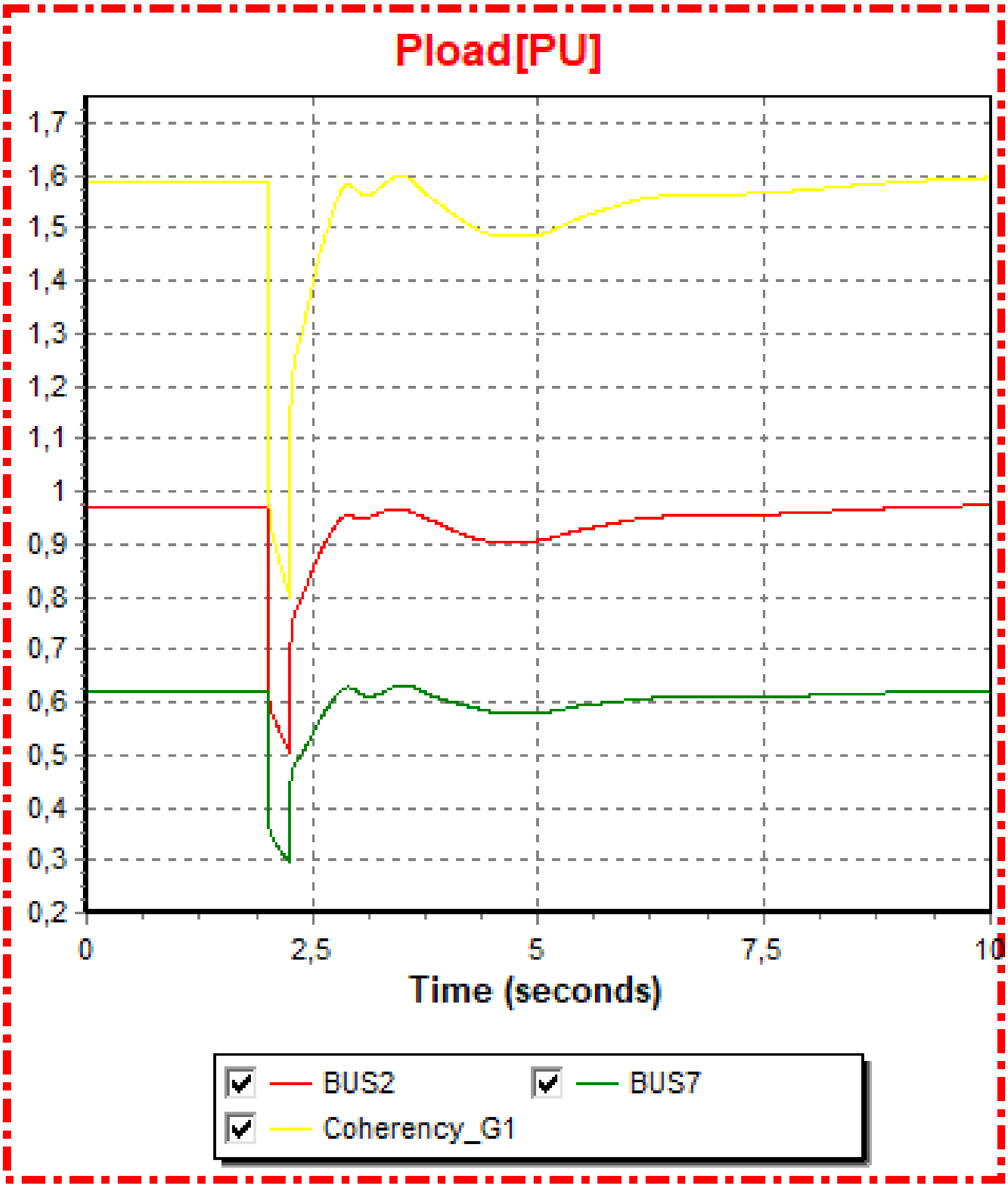


Figure 6.8: Active power of coherent group 1

The next question will be what if a given load bus doesn't have any generator. Then it needs a special attention to group such loads into either electrically closest generator buses, generators in the same voltage level, or create separate load coherent group. Clustering loads into the closest generator buses will help to maintain the dynamics of the loads which are strongly impacted by system disturbances. By aggregating these loads into generators with the same voltage levels the requirement of transformers to connect the equivalent loads can be avoided. It is obvious that clustering all load buses together into one group will simplify the aggregation process but the corresponding dynamic results might not be preserved very well. Therefore, such loads are added into the closest coherent generators of the same voltage level.

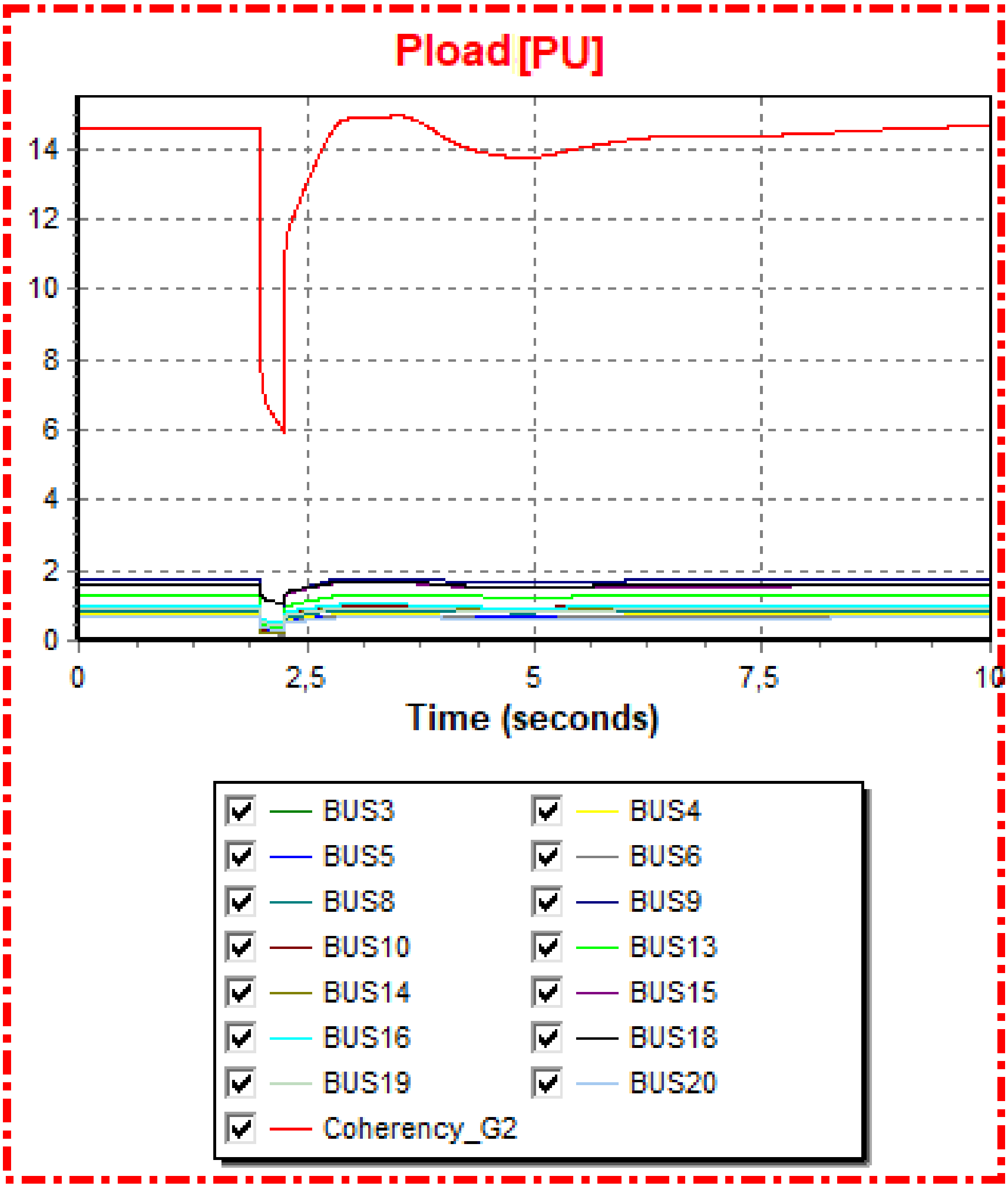


Figure 6.9: Active power of coherent group 2

6.2.2 Impact of Type of Disturbance

Since the dynamics of the machines depend on the type of system disturbance, the coherency level of each generators will also depend on the fault type initiated during the stability study. Therefore, another type of system disturbance has been considered to investigate this impact while aggregating the same model, IEEE 24 bus RTS. For this purpose, a fault that lasts for 0,0125 seconds is applied on a line between bus 15 and 23.

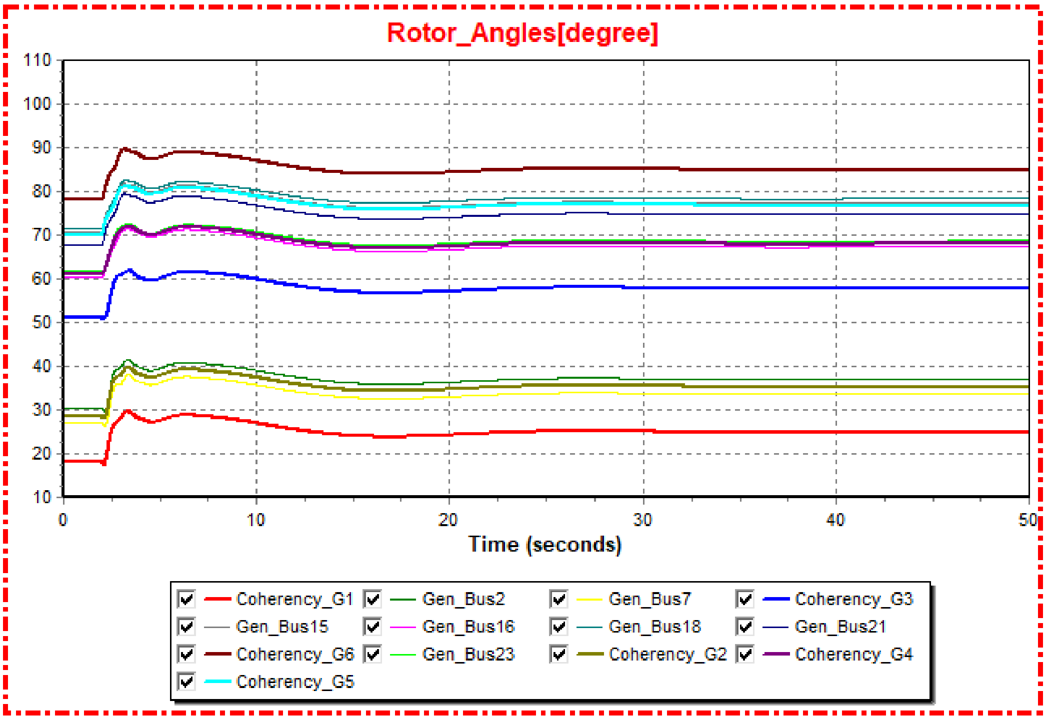


Figure 6.10: Rotor angle responses following a line fault

The rotor angle response of the generators shown in Figure 6.10 indicates that the generators are no more categorized into two coherent groups as it was in the above scenario, with three-phase bus fault. As a result, the generators are divided into six coherent groups with a maximum deviation of 0.085 rad coherency criteria. Using this coherency criterion the coherent generator and load buses are grouped as shown in Table 6.10.

Table 6.10: Generator and load coherent groups following a line fault

Group	**1**	**2**	**3**	**4**	**5**	**6**
Generator Bus	1	2,7	13	16,23	15,18, 21	22
Load Bus	3,4, 5, 6, 8, 9, 10	2,7	13	16	15,18	14,19,20

The generator buses are clustered completely based on the rotor angle coherency criteria while loads which don't contain generator are clustered to the electrically closest generator bus with the same voltage level. Therefore, the first coherent load group contains the load buses at 138 kV are grouped to the closest generator bus which is bus 1. The last group includes loads connected at buses with the voltage level of 230 kV and they are again grouped into a coherent generator group at bus 22. Then, the parameters of each equivalent generator or/and load buses are determined accordingly.

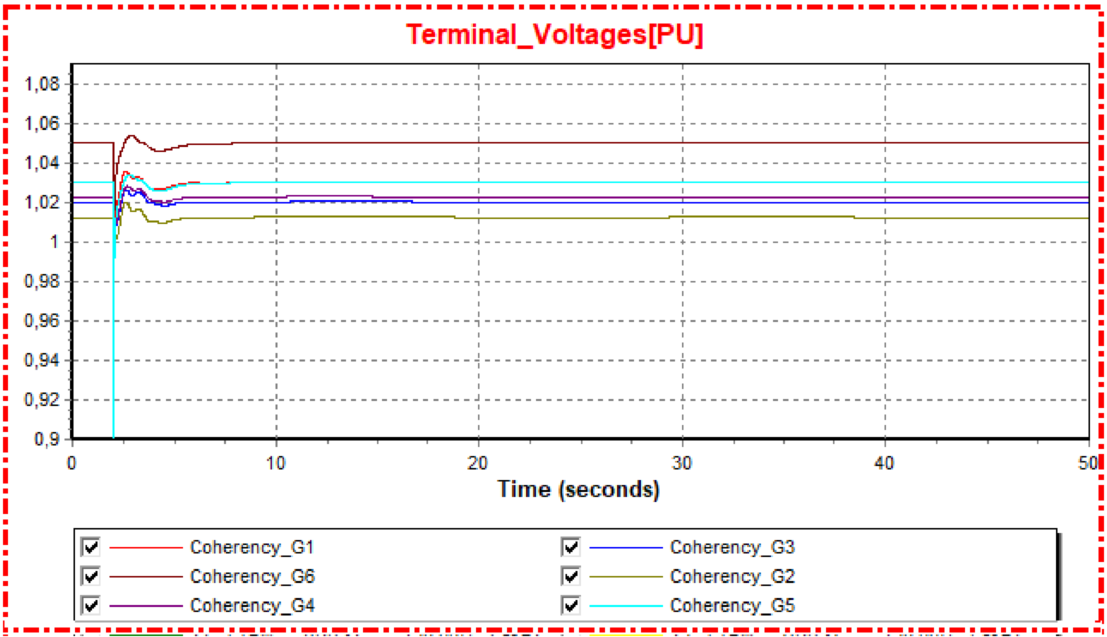


Figure 6.11: Aggregation of generator terminal voltages

The corresponding terminal voltage of each coherent group is represented as shown in Figure 6.11. Since generator coherent groups 1, 3 and 6 represent individual generators at buses 1, 13 and 22 respectively, each unit represents a coherent group. The generator terminal voltage of the rest coherent groups is determined using the average values of individual terminal voltages in the group. Coherent groups 1 and 6 have the same steady state voltage. However, their dynamic response is not the same as group 6 contains deep voltage drop.

Therefore, it is important to consider them as a separate group and represent them using their corresponding dynamic equivalent model.

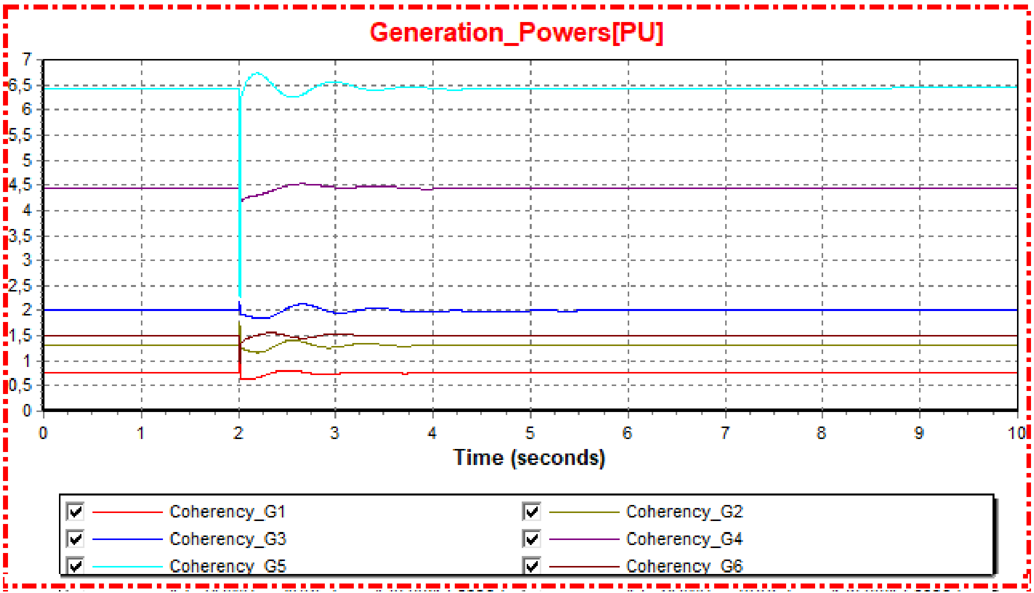


Figure 6.12: Aggregation of power generations

As illustrated in Figure 6.12 the aggregated real power generation of the coherent machines is then determined by adding the generation from each generator in the coherent group. Again it is easier to analyze the detailed dynamics of the coherent groups using these six groups of machines than the above case where only two coherent groups were used to represent the entire model.

Similarly, the active power consumption of each coherent group presented in Table 6.10 are shown in Figure 6.13. This result indicates the largest consumption equivalenced by coherent group 6 represents the main dynamics of the active power consumption. Each aggregated active power consumption are therefore added to their respective generator buses for further simplified representation. Further results of the aggregated reactive power consumption are presented in Appendix A.2.

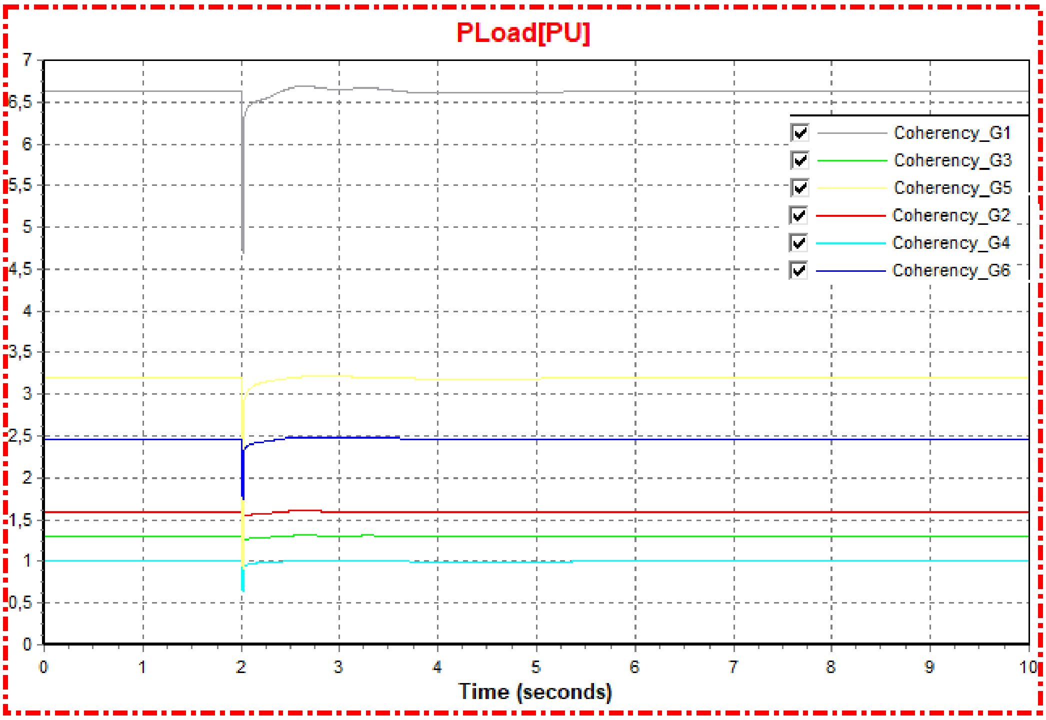


Figure 6.13: Aggregation of active power consumption

6.3 Aggregation of Dynamic Equivalent Parameters

In order to develop an efficient equivalent model that can be used for dynamic studies the aggregated parameters of all the necessary models in the system needs to be determined. The calculations of such parameters for the second case study, IEEE 24 bus RTS, with the scenario under three-phase bus fault are presented in this section. The synchronous generators considered in this network are round rotor type with both d and q-axis damper wingdings and they are of the model GENROU. The exciters, governors and power system stabilizers models are of type IEEEX1, IEESGO, and PSS2A, respectively.

The values of all the aggregated parameters are estimated based on the mathematical derivations presented in section 3.1.1, while discussing how to address the second research question, how to determine the values of the parameters in the equivalent dynamic models. The two synchronous compensators in this model are clustered into the electrically closer group and hence the compensator in bus 6 is grouped into the first coherent group while the one connected in bus 14 is grouped into the second coherent group.

The single line diagram of the equivalent aggregated model can be represented as shown in Figure 6.14 with steady-state results presented in Table 6.11. The values are given in per unit under 100 MVA base value. The two equivalent generator buses are connected through parallel tie-lines. The first line represents the actual line connecting the areas whereas the second one is an equivalent branch determined to retain the admittance of the original system.

Table 6.11: Aggregated Steady State Results of IEEE 24 RTS

Bus_Name	P_G	P_D	Q_D	V_{act}	V_{min}	V_{max}	Base kV
Coherency_G1	5.48	3.3	0.67	1.032	0.95	1.05	138
Coherency_G2	23.43	22.11	5.13	1.017	0.95	1.05	230

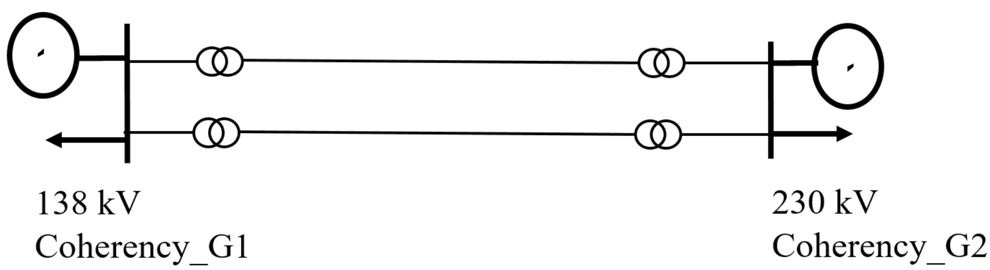


Figure 6.14: Aggregated equivalent circuit of IEEE 24 RTS

The estimated values of the generator dynamic model parameters of these coherent groups are presented in the appendix, Table A.5. The values of all time constants are given in seconds while the voltage limits of the regulators are given in volts. Similarly, the equivalent aggregated dynamic parameters of the exciters in each coherent group are determined using the estimation approaches discussed in the literature review and the aggregated equivalent values can be found in Table A.6.

Since the parameter values of the turbine governor and PSS models are identical their corresponding aggregated time constants are also the same with parameters' value in each model. The aggregated values of gain constants are then determined using the average values of coherent machines' parameter. The complete parameter values of the equivalent aggregated models can be found in Appendix A.2.

Chapter 7

Conclusions and Future Work

7.1 Conclusions

The need for aggregated models has been driven by several reasons of analyzing and monitoring the grid data such as time limitation, memory and power computation, accessibility of network data and the need to gain insight into the detail dynamics of a system, etc. Even though developing an equivalent model would help to solve these problems, the advantage of using aggregated models can be viewed as a trade-off between complexity reduction and misfit of simulation results. Therefore, it is required to have an aggregated model of minimal complexity that optimally approximates the original model with an acceptable misfit. To review recent researches in this area, the most widely used dynamic aggregation techniques: modal analysis, measurement and coherency-based approaches are discussed in this paper. Due to the complexity of analyzing state variables and lack of complete measurement data, it is difficult to apply modal analysis and measurement based aggregations on a very large power system model. Hence, an aggregation methodology based on grid voltage level and coherency identification is developed in this report.

In this section, the main remarkable conclusions are presented based on the findings throughout this report. The conclusions are drawn based on the steady state and dynamic aggregation results discussed in the previous chapter.

7.1.1 Aggregation Based on Steady State Results

An automation based on Python scripts has been developed to aggregate some part of the Norwegian grid model. The aggregations are performed based on voltage levels and the generator and load model parameters in the range of each voltage levels are aggregated to develop the equivalent parameters. The aggregated steady state power flow solutions showed that this methodology can be applied to simplify grid models considering some limitations and the main outcomes can be summarized as:

- Since the system parameters of the models are aggregated based on their voltage levels, it is necessary to consider ideal transformers while developing the interconnection of the equivalent models. This makes it difficult to determine the actual voltage ratio of these transformers connecting the equivalent models at different voltage levels.
- The aggregated steady state results fit with the area results from the detailed model and such methodologies can be used to aggregate models intended for power flow studies and market analysis. However, these results can't be used to make a detailed analysis of steady-state values such as voltage magnitudes and rotor angles of machines in that specific area.
- Even though it gives an easier and clear information about the supply and demand areas, another limitation of aggregating grid models based on steady state results is, it doesn't give the appropriate grouping of generator and load buses as they might require different voltage level definitions.
- The aggregation process doesn't take into account any dynamics and system components. Therefore, machines containing completely different response might be clustered into the same group. As a result, the equivalent steady state results couldn't reflect the exact state of the external subsystem and some important information might lose because of parameter aggregation. Therefore, the resulting aggregated parameters couldn't preserve the dynamic response of the system under investigation. To emphasize on how to preserve system dynamics, an aggregation methodology based on coherency identification has been considered and the main outcomes in using this approach are reviewed in the next section.

7.1.2 Aggregation Based on Dynamic Results

A dynamic equivalencing methodology based on coherency identification of generators has been investigated in section 6.2. This methodology is applied to aggregate the IEEE 24 bus RTS. The impact of a system disturbance on the coherency identification of machines has been studied to keep the main dynamics of the coherent groups. The major conclusion from these simulation results are drawn as follows:

- The aggregation results discussed in section 6.2 show that the dynamic equivalencing based on coherency identification, using rotor angles as a coherency criteria, is a very nice alternative to keep the main dynamics of individual system components. Since coherent groups are made based on their dynamic response this methodology gives better dynamic equivalent models which can be used for stability studies. To have more accurate and efficient aggregated model it is important to know the dynamics of individual system components and the intended use of the aggregated models. This makes it difficult to apply this technique for a very large power system models like the first case study in this report, studying the complete Norwegian grid model.
- In this report, unique model types of generators, exciters, governors and power system stabilizers have been considered which simplifies the task to determine the aggregated parameters of the equivalent system models. However, practically this doesn't exist as the power system models contain several model types of system comments. Therefore, it is important to consider this variety of model types in order to develop accurate equivalent models.
- The coherent groups of a given system differ based on the type, location, severity and duration of the system disturbance under consideration. This makes it difficult to form one unique dynamic equivalent model that can be used to maintain the dynamics of each coherent groups. Therefore, the dynamic equivalent models discussed in this paper are fixed models that represent a specific scenario and hence they can't be used efficiently for applications like online dynamic security assessment. Some recommendations are pointed out at the end of the report to further improve this dynamic aggregation and use it in these application areas.

7.2 Answers to Research Questions

Brief answers to the research questions discussed in the literature review of this report, 3.1.1, are presented in this section. These questions were also a means of motivation for this work to look at the aggregation methodology of the case study as deeper as possible and to check if the aggregation meets the objective of the project.

1. What model order to consider for each equivalent unit and how to cluster network areas so that the crucial properties of the external system will be preserved?

The synchronous generators considered in the case study are of third-order d-q model and the equivalent parameters are determined to keep the same order in the equivalent models. The clusters are made based on a defined coherency criteria of the generator rotor angles. As the dynamic response of the machine varies with the type of system disturbance, a maximum variation criteria of 0.172 rad and 0.086 rad are considered to measure the coherency of each unit and make the coherent groups for these scenarios, three-phase bus and line faults.

2.How to determine the aggregated model parameters such as machine, load, branch, and control system parameters?

The aggregated parameters of the equivalent models are determined based on the mathematical equations presented in section 3.1.1. To mention some, the voltage magnitude and voltage angles are determined by averaging while parameters related to power are calculated by adding the values of individual parameters in the coherent group. Due to the extensive size of the case studies, the calculation of branch parameters and how they need to be treated during the aggregation has not been studied. A brief discussion on this topic can be found in the pre-thesis report, [1].

3. How and where to connect the dynamic equivalent aggregated units and how to represent the final aggregated dynamic model?

In this project, the physical network of the equivalent models have not been simulated with a detail parameter values and therefore it has not been tested how to integrate them with the complete model instead of using the detailed models. However, to give a simple answer to this last question the equivalent models need to be connected to the original model of the same voltage level using ideal transformers.

7.3 Recommendations for Future Work

Despite the work carried out in this report, few assumptions and simplifications were considered to address the main challenges in utilizing a detailed model and on how to develop the equivalent models. Few aspects of this work were newly developed, specially aggregating a grid model using Python automation, and thus still there are some recommendations to be made if further future work is carried out.

- The dynamic aggregations discussed in section 6.2 are based on the assumption that the generator, exciter, turbine governor and PSS are of the same model type. However, in practice, power system grids are built with different types of machine, governor and controller models. Therefore, considering this scenario and applying the dynamic aggregation on a grid containing mixed system models would help to create an aggregated model that fits with the practical power system model.
- As it is mentioned in the project objective , the aim of grid aggregation is to develop a simplified model with less computation burden and at the same time that can maintain the main information for the intended purpose. To utilize these equivalent models applications for stability study purpose, they need to be connected to the study subsystem. Thus, it would be nice to have an equivalent model that can replace the detailed network and finally connect to the remaining part of the system. This will help to use the equivalent model for other purposes than what is intended to and measure their performance.
- Thanks to the development of intelligent devices and their advanced features because of the Internet of Things (IoT), nowadays, the grid infrastructure is becoming smart and self-healing. This will help to utilize these sophisticated system equipments to develop an aggregated models that can be used dynamically regardless of the type of system disturbance. One way to achieve this is by applying a measurement-based aggregation as discussed in section 3.2.

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Appendix A

Further Results

A.1 Aggregated Steady State Power Flow Solutions

Table A.1: Aggregation of the grid network up to 10 kV [a]

Bus	Base kV	**Pg**	**P**$_{max}$	**X"**	**X'**	**X**	**X**$_s$	**V**$_{act}$	**V**$_{sch}$	$\delta(deg)$
57487	6.6	5.00	9.80	0.18	0.29	1.02	0.22	0.980	0.980	106.02
57516	7.5	40.00	40.00	0.17	0.24	0.24	0.17	1.040	1.040	106.83
57506	8.0	18.36	20.40	0.16	0.27	1.00	0.16	1.0687	1.100	111.59
57566	8.0	24.70	25.00	0.23	0.32	0.32	0.23	1.000	1.000	107.73
57486	8.5	0.00	32.00	0.16	0.21	0.21	0.16	0.995	1.000	42.47
57498	8.8	49.50	52.80	0.32	0.32	1.20	0.21	1.030	1.030	114.91
57536	9.5	75.00	75.00	0.19	0.30	1.20	0.19	0.990	0.990	115.00
57436	9.8	75.00	75.00	0.21	0.31	1.30	0.21	1.000	1.000	107.73
57056	10.0	54.20	58.00	0.15	0.23	0.23	0.15	1.000	1.000	-77.19
57057	10.0	55.30	58.00	0.15	0.23	0.23	0.15	1.000	1.000	-77.04
57058	10.0	55.70	58.00	0.15	0.23	0.23	0.15	1.0568	1.000	-76.84
Eq_Bus1	**10.0**	**452.76**	**504.00**	**0.02**	**0.02**	**0.03**	**0.02**	**1.015**	**1.010**	**52.84**

[a]Note that the values of X", X', X,X_s, V_{act} and V_{sch} are given in per unit where as Pg and P$_{max}$ are given in MW.

Table A.2: Aggregation of the grid network 11 kv to 15 kv

Bus	Base kV	**Pg**	**P**$_{max}$	**X"**	**X'**	**X**	**X**$_s$	**V**$_{act}$	**V**$_{sch}$	$\delta(deg)$
57096	10.5	18.90	26.60	0.17	0.26	0.26	0.17	0.9600	0.96	107.96
57059	11.0	29.70	42.00	0.20	0.23	0.23	0.20	0.9705	0.91	-79.52
57386	11.0	60.70	63.00	0.20	0.30	0.30	0.20	0.9900	0.99	108.76
57476	11.0	57.80	60.40	0.14	0.28	1.21	0.14	1.0155	0.88	94.55
57477	11.0	26.20	26.40	0.13	0.27	1.23	0.13	0.9000	0.90	113.56
57496	11.0	18.40	20.00	0.18	0.35	0.35	0.18	0.9500	0.95	46.07
57526	11.0	33.30	40.00	0.19	0.30	1.23	0.19	0.9800	0.98	111.48
57527	11.0	33.00	40.00	0.19	0.30	1.23	0.19	0.9800	0.98	111.43
57546	11.0	35.00	35.00	0.28	0.30	1.15	0.19	0.9900	0.99	115.12
Eq_Bus2	**11.0**	**765.76**	**857.40**	**0.02**	**0.03**	**0.05**	**0.02**	**0.9750**	**0.96**	**78.225**

Table A.3: Aggregation of the grid network 16 to 22 kv

Bus	Base kV	**Pg**	**P**$_{max}$	**X"**	**X'**	**X**	**X**$_s$	**V**$_{act}$	**V**$_{sch}$	$\delta(deg)$
57108	17.0	0.00	0.00	0.20	0.20	0.20	0.20	0.9727	0.98	97.76
57445	20.0	33.20	36.70	0.16	0.25	1.03	0.17	1.0826	1.13	100.34
57445	20.0	3.00	5.00	0.20	0.30	0.30	0.20	1.1118	1.13	58.09
57120	22.0	29.00	39.10	1.00	1.00	1.00	inf	1.0000	1.00	89.99
57128	22.0	4.00	51.00	1.00	1.00	1.00	inf	1.0200	1.02	85.95
57129	22.0	17.00	57.50	1.00	1.00	1.00	inf	1.0200	1.02	86.85
57407	22.0	29.50	55.20	0.31	0.20	0.20	0.31	1.0189	1.02	66.77
Eq_Bus3	**22.0**	**949.46**	**1176.90**	**0.05**	**0.05**	**0.06**	**0.05**	**1.0170**	**1.02**	**89.053**

Table A.4: Aggregation of the grid network 23 to 66 kv

Bus	Base kV	**Pg**	$\mathbf{P}_{max}$	**X"**	**X'**	**X**	$\mathbf{X}_s$	$\mathbf{V}_{act}$	$\mathbf{V}_{sch}$	$\delta(deg)$
56544	66.0	20.00	31.00	0.20	0.60	0.60	0.20	1.0000	1.00	55.93
57034	66.0	176.00	182.40	0.20	0.40	0.40	0.20	0.9800	0.98	64.44
57044	66.0	32.00	32.60	0.20	0.40	0.40	0.20	0.9818	0.97	62.90
57054	66.0	4.00	17.50	0.19	0.40	0.40	0.19	1.0194	1.02	70.46
57114	66.0	130.00	132.40	0.17	0.40	0.40	0.17	0.9700	0.97	76.25
57116	66.0	35.50	37.00	0.16	0.26	1.25	0.16	1.0000	1.00	95.34
57124	66.0	71.00	91.00	0.20	0.40	0.40	0.20	1.0000	1.00	82.66
57127	66.0	10.00	15.00	0.19	0.30	0.30	0.19	1.0200	1.02	84.97
57424	66.0	40.00	63.00	0.17	0.40	0.40	0.17	0.9881	1.06	64.74
57428	66.0	3.00	6.00	0.20	0.40	0.40	0.20	1.0000	1.00	66.10
57456	66.0	3.00	5.00	0.22	0.30	0.30	0.22	1.0000	1.00	67.99
57528	66.0	30.00	30.00	0.21	0.32	0.32	0.21	1.0000	1.00	70.31
57528	66.0	10.00	20.00	0.19	0.30	0.30	0.19	0.9881	1.00	69.25
Eq_Bus4	**66.0**	**368.50**	**449.50**	**0.01**	**0.03**	**0.03**	**0.01**	**0.9970**	**1.00**	**73.72**

A.2 Aggregation of Dynamic Parameters Based on Stability of Machines

Table A.5: Aggregation of Generators' Dynamic Parameters

Bus	Tdo'	Tdo"	Tqo'	Tqo"	H	D	xd	xq	xd'	xq'	xd"=xq"	Xl	Pmax MW
1	4.767	0.033	0.413	0.070	3.000	0.000	2.198	2.097	0.311	0.506	0.233	0.194	200
2	7.899	0.040	0.597	0.079	4.760	0.000	2.287	2.174	0.265	0.464	0.193	0.146	100
7	7.899	0.040	0.597	0.079	4.760	0.000	2.287	2.174	0.265	0.464	0.193	0.146	100
6	5.700	0.030	1.500	0.040	3.580	0.000	1.495	2.370	0.531	0.331	0.026	0.304	0
Eq1	**6.266**	**0.035**	**0.621**	**0.062**	**4.025**	**0.000**	**0.500**	**0.550**	**0.079**	**0.107**	**0.019**	**0.045**	**400**
13	9.480	0.023	0.990	0.035	7.500	0.000	2.170	2.050	0.220	0.360	0.175	0.150	250
15	7.203	0.046	0.800	0.069	4.810	1.500	1.873	1.848	0.374	0.548	0.289	0.239	300
16	7.203	0.046	0.800	0.069	4.810	1.500	1.873	1.848	0.374	0.548	0.289	0.239	300
18	5.941	0.035	0.565	0.070	5.025	0.000	1.995	1.881	0.250	0.445	0.186	0.141	150
21	7.203	0.046	0.800	0.069	4.810	1.500	1.873	1.848	0.374	0.548	0.289	0.239	300
22	9.733	0.047	1.081	0.082	6.350	0.000	2.059	2.006	0.267	0.452	0.201	0.171	180
23	9.480	0.023	0.990	0.035	7.500	0.000	2.170	2.050	0.220	0.360	0.175	0.150	250
14	7.300	0.030	0.400	0.040	3.480	0.000	1.540	2.410	0.500	0.300	0.465	0.224	0
Eq2	**7.726**	**0.034**	**0.730**	**0.053**	**5.536**	**0.563**	**0.240**	**0.247**	**0.037**	**0.053**	**0.029**	**0.023**	**1730**

Table A.6: Aggregation of Exciters' Dynamic Parameters

Bus	KA	TA	VRMAX	VRMIN	KE	TE	KF	TF1	E1	SE(E1)
1	50.000	0.060	5.000	-5.000	1.000	0.250	0.090	1.000	3.000	2.000
2	60.200	0.050	5.200	-5.000	1.000	0.410	0.090	0.500	4.000	0.880
7	50.000	0.060	5.000	-5.000	1.000	0.500	0.090	1.000	4.000	0.310
6	50.000	0.060	5.000	-5.000	1.000	0.500	0.080	1.000	4.000	0.340
Eq1	**52.914**	**0.057**	**4.957**	**-4.957**	**0.883**	**0.383**	**0.088**	**0.800**	**3.750**	**0.883**
13	60.200	0.050	5.200	-5.000	1.000	0.410	0.090	0.500	4.000	0.880
15	40.000	0.020	6.500	-6.500	1.000	0.730	0.090	1.000	4.000	0.740
16	50.000	0.020	5.000	-5.000	1.000	0.528	0.090	1.260	4.000	0.280
18	40.000	0.020	5.500	-5.500	1.000	0.400	0.090	1.000	4.000	0.850
21	50.000	0.020	5.500	-5.500	1.000	0.400	0.090	1.000	4.000	0.850
22	40.000	0.020	5.500	-5.500	1.000	0.400	0.090	1.000	4.000	0.850
23	60.200	0.050	5.200	-5.000	1.000	0.410	0.090	0.500	4.000	0.880
14	50.000	0.020	5.000	-5.000	1.000	0.471	0.080	1.250	4.000	0.250
Eq2	**46.788**	**0.012**	**6.369**	**-6.369**	**0.698**	**0.450**	**0.089**	**0.834**	**4.000**	**0.698**

A.3 Dynamic Aggregation of Reactive Loads

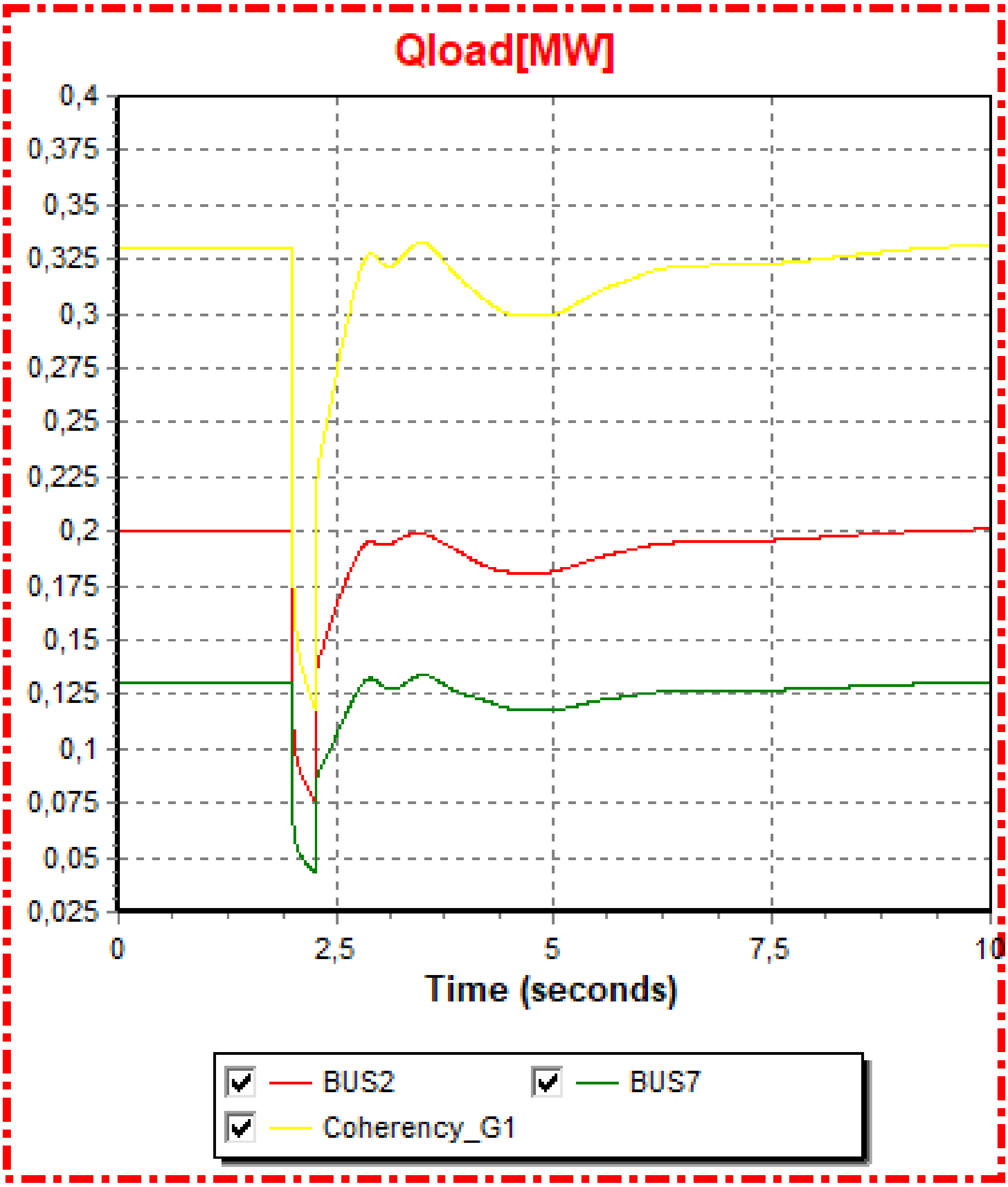

Figure A.1: Reactive power of coherent group 1 after a bus fault

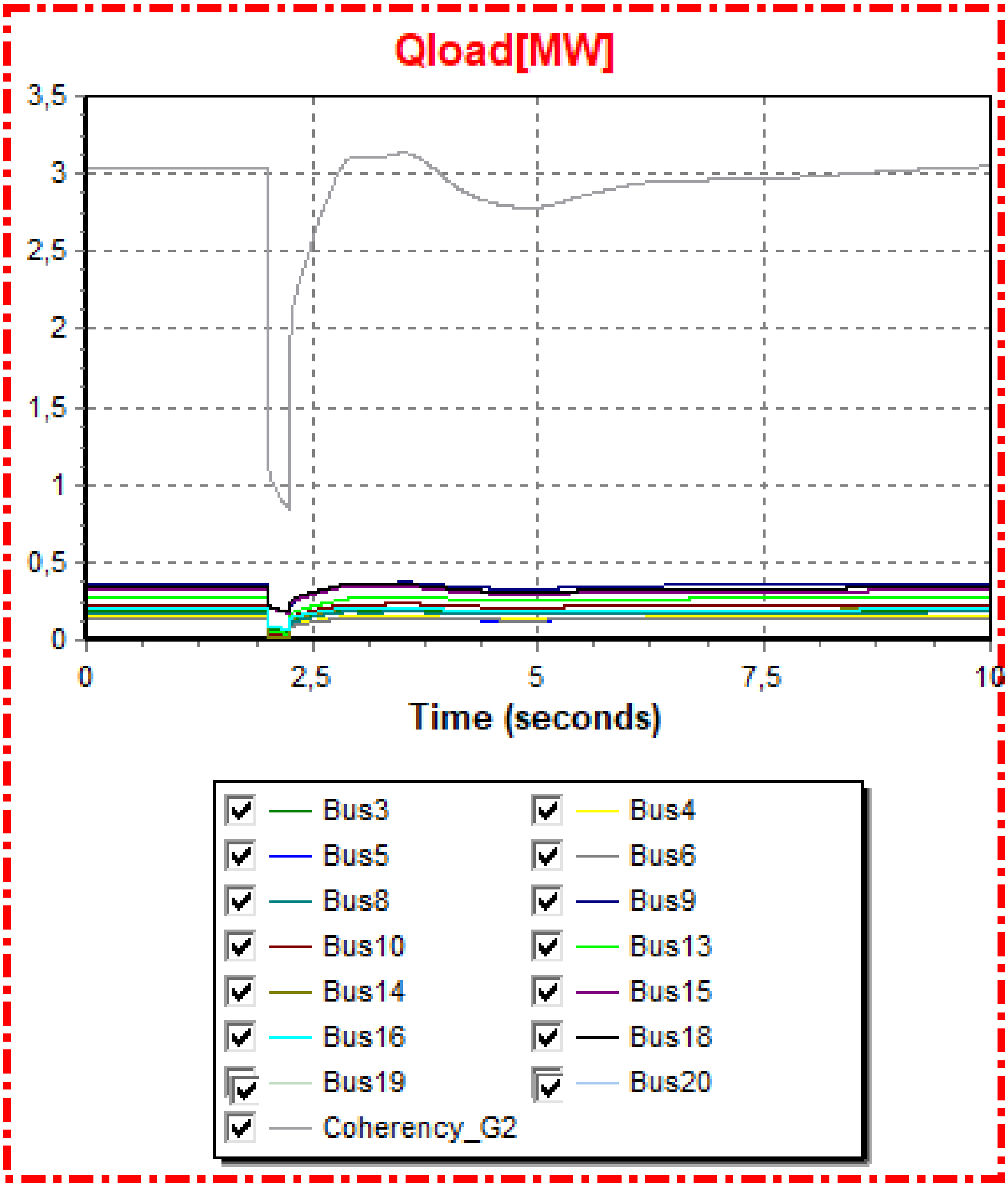

Figure A.2: Reactive power of coherent group 2 after a bus fault

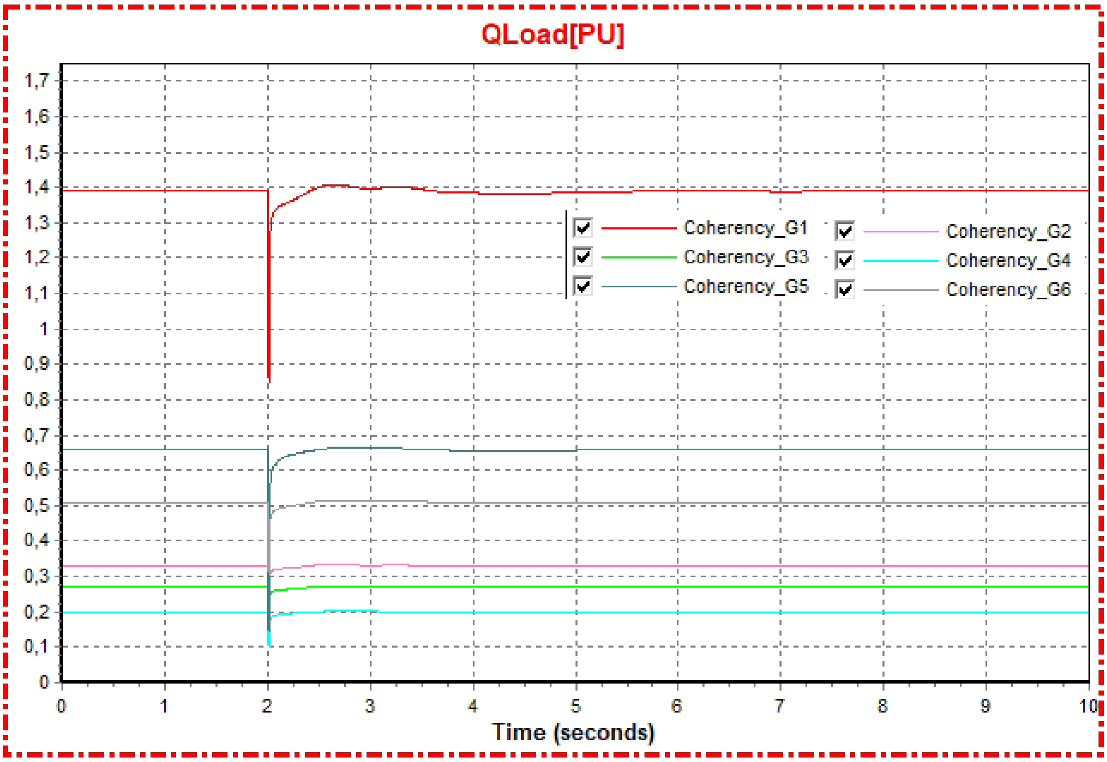

Figure A.3: Aggregation of reactive power consumption after a line fault

Appendix B
Python Scripts

B.1 Python Script for Generator Bus Aggregation Based on Voltage Levels

```
##############################################
import numpy as np
import pssepath
pssepath.add_pssepath()
import psspy
import redirect
import excelpy
import csv
import numpy
#################################################
#Redirect output from PSSE to Python:
redirect.psse2py()
#Initializing PSSE to run up to 10,000 buses
psspy.psseinit(10000)
#############################################
#Set PSSE and Python Files' Path ##path='C:\PTI\PSSE33\Thesis'##
Study_Model='Norge2015_tunglast_09A'
sav_file='%s'%Study_Model
conv_file='%s_conv'%Study_Model
```

```
dyr_file='Norge2015_09A'
Gen_Agg='Gen_Agg' #Excel file to store the generator bus aggregated results
################################################
"""Preparing for stability run"""
psspy.case(Study_Model)
#Converting generators into a current source model to intialize the in-service
    machines in the working case.
psspy.cong(0)
#Converting reactive loads into constant impedance and active loads into
    constant current types
psspy.conl(0,1,1,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,2,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,3,[0,0],[ 60.0, 40.0,0.0, 100.0])
#The next three steps orders the buses for sparsity, facterize matrix A of the
    system and perform the simplified load flow calculations.
psspy.ordr(1)
psspy.fact()
psspy.tysl(0)
#Saving the converted case for further stability run
psspy.save(conv_file)
psspy.case(conv_file)
#Creating Voltage level Scenarios to aggragte the grid part with area code 66.
#where:
       #Group1: 0<basekv<10kv
       #Group2: 10.1<basekv<15kv
       #Group3: 15.1<basekv<22kv
       #Group4: 22.1<basekv<66kv
Escenarios=['Group1', 'Group2', 'Group3', 'Group4']
rowid = 1
vmin=0
Vmax=66
SizeEscenarios=len(Escenarios)
 # Open and Show excel to extract the grid data and report aggragated results
```

```
x1 = excelpy.workbook()
x1.show()
for jj in range(0,SizeEscenarios):
    rowid +=1
    CASE=Escenarios[jj]
    if CASE=='Group1':
       vmin=0
       vmax=10
    elif CASE=='Group2':
       vmin=10.1
       vmax=15
    elif CASE=='Group3':
       vmin=15.1
       vmax=22
    elif CASE=='Group4':
       vmin=22.1
       vmax=66
     #Iterative subsystem definitions for the above scenarios
    ierr=psspy.bsys(
      sid=1,
      usekv=1,            # filter based on Base kV
      basekv=[vmin,vmax],  # select buses with base voltage on the range vmin to
          vmax
      numarea=21,
      areas=[66],          # targeted only buses in area 66
    )
    #Reteriving generator data of the targeted area and voltage levels
    ierr, bus_numbers = psspy.agenbusint(1,2,string='NUMBER')
    ierr, bus_names = psspy.agenbuschar(1,2, string='NAME')
    ierr, voltage_actuals = psspy.agenbusreal(1,2,string='PU')
    ierr, voltage_schedules = psspy.agenbusreal(1,2,string='VSPU')
    ierr, Voltage_angles = psspy.agenbusreal(1,2,string='ANGLE')
    ierr, real_powers = psspy.agenbusreal(1,2,string='O_PGEN')
```

```
    ierr, base_voltages = psspy.agenbusreal(1,2,string='BASE')
    bus_numbers = bus_numbers[0]
    bus_names = bus_names[0]
    voltage_actuals = voltage_actuals[0]
    voltage_schedules = voltage_schedules[0]
    Voltage_angles = Voltage_angles[0]
    real_powers = real_powers[0]
    base_voltages = base_voltages[0]

# Write Title of each each case on the Excel sheet
    x1.set_cell((rowid, 1), 'Voltage Level: %s' %CASE)
    rowid +=1
    x1.set_cell((rowid, 1), 'Bus_Number')
    x1.set_cell((rowid, 2), 'Bus_Name')
    x1.set_cell((rowid, 3), 'Base[kv]')
    x1.set_cell((rowid, 4), 'Volact [pu]')
    x1.set_cell((rowid, 5), 'Angle [rad]')
    x1.set_cell((rowid, 6), 'Pgen [MW]')
    # Arranging the PSSE format data and writing it to the excel sheet

    for k in range(len(bus_numbers)):
            rowid +=1
            bus_number = bus_numbers[k]
            bus_name = bus_names[k]
            voltage_actual = voltage_actuals[k]
            voltage_schedule = voltage_schedules[k]
            Voltage_angle = Voltage_angles[k]
            real_power = real_powers[k]
            base_voltage= base_voltages[k]
            x1.set_cell((rowid, 1), bus_number)
            x1.set_cell((rowid, 2), bus_name)
            x1.set_cell((rowid, 3), round(base_voltage,1))
            x1.set_cell((rowid, 4), round(voltage_actual,3))
```

```
            x1.set_cell((rowid, 5), round(Voltage_angle,3))
            x1.set_cell((rowid, 6), round(real_power,3))
    rowid +=1
    #Aggregation of external subsystem baesd on the specified subsystem
        definition
    x1.set_cell((rowid, 1), CASE)
    x1.set_cell((rowid, 2), 'Eq_GenBus')
    x1.set_cell((rowid, 3), round(numpy.max(base_voltages),1))
    x1.set_cell((rowid, 4), round(numpy.mean(voltage_actuals),3))
    x1.set_cell((rowid, 5), round(numpy.mean(Voltage_angles),3))
    x1.set_cell((rowid, 6), round(numpy.sum(real_powers),3))
x1.save('%s.xlsx'%Gen_Agg)
x1.close()
psspy.pssehalt_2()
```

B.2 Python Script for Load Bus Aggregation Based on Voltage Levels

```
###########################################
import numpy as np
import pssepath
pssepath.add_pssepath()
import psspy
import redirect
import excelpy
import csv
import numpy
#############################################
#Redirect output from PSSE to Python:
redirect.psse2py()
#Initializing PSSE to run up to 10,000 buses
psspy.psseinit(10000)
#############################################
#Set PSSE and Python Files' Path ##path='C:\PTI\PSSE33\Thesis'##
Study_Model='Norge2015_tunglast_09A'
sav_file='%s'%Study_Model
conv_file='%s_conv'%Study_Model
dyr_file='Norge2015_09A'
Load_Agg='Load_Agg' #Excel file to store the load bus aggregated results
################################################
"""Preparing for stability run"""
#
psspy.case(sav_file)
#Converting generators into a current source model to intialize the in-service
   machines in the working case.
psspy.cong(0)
#Converting reactive loads into constant impedance and active loads into
   constant current types
```

```
psspy.conl(0,1,1,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,2,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,3,[0,0],[ 60.0, 40.0,0.0, 100.0])
#The next three steps orders the buses for sparsity, facterize matrix A of the
   system and perform the simplified load flow calculations.
psspy.ordr(1)
psspy.fact()
psspy.tysl(0)
#Saving the converted case for further stability run
psspy.save(conv_file)
psspy.case(conv_file)
#Loading the dynamic file and user defined models
psspy.dyre_new([1,1,1,1],dyr_file)
#Perform a test run on the converted case without any disturbance
psspy.run(0, 10.0,100,1,0)
#Creating Voltage level Scenarios to aggragte the grid part with area code 66.
#where:
       #Group1: 0<basekv<15kv
       #Group2: 15.1<basekv<22kv
       #Group3: 22.1<basekv<66kv
Escenarios=['Group1', 'Group2', 'Group3']
rowid = 1
vmin=0
Vmax=66
SizeEscenarios=len(Escenarios)
 # Open and Show excel to extract the grid data and report aggragated results
x1 = excelpy.workbook()
x1.show()
for jj in range(0,SizeEscenarios):
    rowid +=1
    CASE=Escenarios[jj]
    if CASE=='Group1':
       vmin=0
```

```
        vmax=15
    elif CASE=='Group2':
        vmin=15.1
        vmax=22
    elif CASE=='Group3':
        vmin=22.1
        vmax=66
     #Iterative subsystem definitions for the above scenarios
    ierr=psspy.bsys(
      sid=1,
      usekv=1,            # filter based on Base kV
      basekv=[vmin,vmax],  # select buses with base voltage on the range vmin to
          vmax
      numarea=21,
      areas=[66],          # targeted only buses in area 66
    )
    #Reteriving generator data of the targeted area and voltage levels
    ierr, bus_numbers = psspy.alodbusint(1,2,string='NUMBER')
    ierr, bus_names = psspy.alodbuschar(1,2, string='NAME')
    ierr, voltage_actuals = psspy.alodbusreal(1,2,string='PU')
    #ierr, voltage_schedules = psspy.abusreal(1,2,string='VSPU')
    ierr, voltage_angles = psspy.alodbusreal(1,2,string='ANGLE')
    ierr, real_powers = psspy.alodbusreal(1,2,string='O_ILACT')
    ierr, reactive_powers = psspy.alodbusreal(1,2,string='O_YLACT')
    ierr, base_voltages = psspy.alodbusreal(1,2,string='BASE')
    bus_numbers = bus_numbers[0]
    bus_names = bus_names[0]
    voltage_actuals = voltage_actuals[0]
    reactive_powers = reactive_powers[0]
    voltage_angles = voltage_angles[0]
    real_powers = real_powers[0]
    base_voltages = base_voltages[0]
```

```
# Write Title of each each case on the Excel sheet
    x1.set_cell((rowid, 1), 'Voltage Level: %s' %CASE)
    rowid +=1
    x1.set_cell((rowid, 1), 'Bus_Number')
    x1.set_cell((rowid, 2), 'Bus_Name')
    x1.set_cell((rowid, 3), 'Base[kv]')
    x1.set_cell((rowid, 4), 'Volact[pu]')
    x1.set_cell((rowid, 5), 'Angle[rad]')
    x1.set_cell((rowid, 6), 'ConILoad [MW]')
    x1.set_cell((rowid, 7), 'ConYLoad [MW]')
    # Arranging the PSSE format data and writing it to the excel sheet

    for k in range(len(bus_numbers)):
            rowid +=1
            bus_number = bus_numbers[k]
            bus_name = bus_names[k]
            voltage_actual = voltage_actuals[k]
            reactive_power = reactive_powers[k]
            voltage_angle = voltage_angles[k]
            real_power = real_powers[k]
            base_voltage= base_voltages[k]
            x1.set_cell((rowid, 1), bus_number)
            x1.set_cell((rowid, 2), bus_name)
            x1.set_cell((rowid, 3), round(base_voltage,1))
            x1.set_cell((rowid, 4), round(voltage_actual,3))
            x1.set_cell((rowid, 5), round(voltage_angle,3))
            x1.set_cell((rowid, 6), round(real_power,3))
            x1.set_cell((rowid, 7), round(reactive_power,3))

    #Aggregation of external subsystem baesd on the specified subsystem
        definition
    rowid +=1
    x1.set_cell((rowid, 1), CASE)
```

```
    x1.set_cell((rowid, 2), 'Eq_Bus')
    x1.set_cell((rowid, 3), round(numpy.max(base_voltages),1))
    x1.set_cell((rowid, 4), round(numpy.mean(voltage_actuals),3))
    x1.set_cell((rowid, 5), round(numpy.mean(voltage_angles),3))
    x1.set_cell((rowid, 6), round(numpy.sum(real_powers),3))
    x1.set_cell((rowid, 7), round(numpy.sum(reactive_powers),3))
x1.save('Load_Agg.xlsx')
x1.close()
psspy.pssehalt_2()
```

B.3 Python Script for Coherency Based Dynamic Aggregation

```
###############################################
import numpy as np
import pssepath
pssepath.add_pssepath()
import psspy
import redirect
import excelpy
import csv
import numpy
import pssplot
#################################################
#Redirect output from PSSE to Python:
redirect.psse2py()
#Initializing PSSE to run up to 10,000 buses
psspy.psseinit(10000)
#############################################
#Set PSSE and Python Files' Path ##path='C:\PTI\PSSE33\Thesis'##
Study_Model='IEEE24'
sav_file='%s'%Study_Model
conv_file='%s_conv'%Study_Model
dyr_file='%s'%Study_Model
#Write to output file
channel_output1='%s_Case1'%Study_Model
channel_output2='%s_Case2'%Study_Model
################################################
"""Preparing for stability run"""
psspy.case(Study_Model)
#Converting generators into a current source model to intialize the in-service
   machines in the working case.
```

```
psspy.cong(0)
#Converting reactive loads into constant impedance and active loads into
    constant current types
psspy.conl(0,1,1,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,2,[0,0],[ 60.0, 40.0,0.0, 100.0])
psspy.conl(0,1,3,[0,0],[ 60.0, 40.0,0.0, 100.0])
#The next three steps orders the buses for sparsity, facterize matrix A of the
    system and perform the simplified load flow calculations.
psspy.ordr(1)
psspy.fact()
psspy.tysl(0)
psspy.save(conv_file)
psspy.case(conv_file)
psspy.case(dyr_file)
#Selecting parameters to sent to the channel output file
psspy.chsb(0,1,[-1,-1,-1,1,1,0])#Generator rotor angle
psspy.chsb(0,1,[-1,-1,-1,1,2,0])#Generator terminal voltage
psspy.chsb(0,1,[-1,-1,-1,1,3,0])#Active power generation
psspy.chsb(0,1,[-1,-1,-1,1,4,0])#Active load power
psspy.chsb(0,1,[-1,-1,-1,1,25,0])#Reactive load power
psspy.chsb(0,1,[-1,-1,-1,1,26,0])#Bus voltage
psspy.chsb(0,1,[-1,-1,-1,1,13,0])#Generator mechanical power
###################################################################
#Case 1 : Coherency identification after a bus fault
####################################################################
#Initialize simulation and load initial conditons to channel output file
psspy.strt(0,channel_output1)
pssplot.openchandatafile(channel_output1)
#Run simulation for 2 seconds to see intial conditions works fine
#intiate bus fault at bus number 11 and clear it after 0.25 seconds
#finally simulate till 15 seconds to study the dynamics of the machines
#this respons is recorded in the channel output file
#to determine the coherecny of the machines
```

```
psspy.run(0, 2.0,100,1,0)
psspy.dist_bus_fault(11,3, 230.0,[0.0,0.0])
psspy.run(0, 2.25,100,1,0)
psspy.dist_clear_fault(1)
psspy.run(0, 15.0,100,1,0)
###################################################################
#Case 2 : Coherency identification after a line fault
####################################################################
psspy.strt(0,channel_output2)
pssplot.openchandatafile(channel_output2)
psspy.strt(0,channel_output2)
psspy.run(0, 2.0,100,1,0)
#initiate line fault between buses 15 and 24 with 230kV base voltage
psspy.dist_branch_fault(15,24,r"""1""",3, 230.0,[0.0,0.0])
psspy.run(0, 2.0125,100,1,0)
psspy.dist_clear_fault(1)
psspy.run(0, 15.0,100,1,0)
psspy.pssehalt_2()
```

Appendix C

Network Data

C.1 Bus Data

Table C.1: Bus data of IEEE 24 bus RTS (in p.u.) [30]

Bus	PG	PD	QD	Vact	Vmin	Vmax	Base kV
1	1.3796	1.08	0.22	1.035	0.95	1.05	138
2	1.3796	0.97	0.20	1.035	0.95	1.05	138
3	0.0000	1.80	0.37	0.991	0.95	1.05	138
4	0.0000	0.74	0.15	0.998	0.95	1.05	138
5	0.0000	0.71	0.14	1.019	0.95	1.05	138
6	0.0000	1.36	0.28	1.013	0.95	1.05	138
7	2.7231	1.25	0.25	1.025	0.95	1.05	138
8	0.0000	1.71	0.35	0.992	0.95	1.05	138
9	0.0000	1.75	0.36	1.002	0.95	1.05	138
10	0.0000	1.95	0.40	1.028	0.95	1.05	138
11	0.0000	0.00	0.00	0.989	0.95	1.05	230
12	0.0000	0.00	0.00	1.002	0.95	1.05	230
13	4.6406	2.65	0.54	1.020	0.95	1.05	230
14	0.0000	1.94	0.39	0.980	0.95	1.05	230
15	1.4069	3.17	0.64	1.014	0.95	1.05	230
16	1.4069	1.00	0.20	1.017	0.95	1.05	230
17	0.0000	0.00	0.00	1.039	0.95	1.05	230
18	3.6307	3.33	0.68	1.050	0.95	1.05	230
19	0.0000	1,18	0.37	1.023	0.95	1.05	230
20	0.0000	1,28	0.26	1.038	0.95	1.05	230
21	3.6307	0.00	0.00	1.050	0.95	1.05	230
22	2.7228	0.00	0.00	1.050	0.95	1.05	230
23	5.9907	0.00	0.00	1.050	0.95	1.05	230
24	0.0000	0.00	0.00	0.982	0.95	1.05	230