



UNIVERSIDAD PONTIFICIA COMILLAS
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master's Thesis

**Allocation of Distribution Losses among
Regions**

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Supervisor: Mauricio Remacha Moro
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Madrid, July 2015

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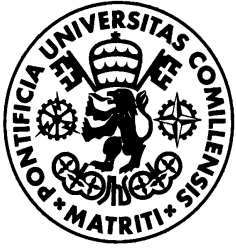
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Summary

The present research was developed in conjunction with the Department of Statistics and Information (DEI) of Red Eléctrica de España. Recently REE has been asked to bring more specific information for the geopolitical regions, known as autonomous communities, regarding the energy balance. REE do not have access to many of the information at the distribution level, thus the allocation of the distribution losses per region has to be estimated.

The motivation of the research is to find a way to be able to estimate losses from a reduced availability of information. The difficulty arises because of the fact that distribution flow interchanges between regions are unknown. Currently DEI allocate losses based in a weighted average on demand, meaning that the present methodology ignores the effect of the distributed generation and the location of both load and generation in the different levels.

The revision of literature revealed that this problem has never been faced before so it was necessary to start from the hypothesis that allocation methods used to assign the responsibility in energy markets could be used as a proxy to determine the losses contained in a geopolitical region. From the several method analyzed, it was determined that a method consisting in estimating losses from coefficients was the most appropriate to apply. Losses coefficients are obtained from past data, so the computation of losses would only require knowing demand and generation for a simplified four-layer model.

A validation was done with a test system and results were successful, obtaining an error with a lower deviation than the methodology currently applied. Results also validated the hypothesis that losses allocation to participants could be used to quantify the losses belonging to a region.

The methodology was applied with real data from Spanish system for January of 2013 to show the process that has to be taken. A losses equation to allocate among regions considering the demand, generation, flows from transmission, international imports and exports at the distribution level was obtained. The final output showed coherency regarding the effect of distributed generation and low voltage loads. Results were similar to those derived from the actual procedure applied by DEI in REE and the ones obtained applying standard losses.

The thesis reflected that some aspects require improvements in DEI in order to obtain more accurate results when allocating losses. The first step is to be able to access the information regarding the flows from transmission to distribution in order to obtain directly the losses in the transmission level, but it is also important because the proposed methodology require computing losses from injections coming from the transmission level.

Resumen

La presente investigación fue desarrollada en conjunto con el Departamento de Estadística e Información (DEI) de Red Eléctrica de España. Recientemente se le ha solicitado a REE brindar información más detallada en lo que respecta a las regiones geopolíticas, conocidas como comunidades autónomas, con respecto al balance energético. REE no posee el acceso a mucha de la información a nivel de distribución, por lo que la asignación de las pérdidas de distribución debe ser estimada. La motivación de la investigación es la de encontrar una manera que permita estimar las pérdidas a partir de poca disponibilidad de información. La dificultad surge básicamente por el hecho de que se desconocen los intercambios regionales en distribución. Actualmente el DEI asigna las pérdidas ponderando con la demanda, lo cual implica que la metodología actual ignora el efecto de la generación distribuida y la ubicación de tanto la generación como de la demanda en los distintos niveles de voltaje.

La revisión de literatura reveló que el problema no ha sido atacado con anterioridad por lo que fue necesario establecer la hipótesis de que los métodos empleados para asignar la responsabilidad de las pérdidas en el Mercado pueden ser usados como una aproximación para determinar las pérdidas en una región. A partir de los métodos analizados se determinó que una metodología consistente en la estimación de pérdidas a partir de coeficientes era la más apropiada de aplicar. Los coeficientes de pérdidas son obtenidos de información pasada, por lo que el cálculo de las pérdidas puede ser posible conociendo la demanda y la generación clasificada siguiendo un modelo simplificado de 4 capas.

Se efectuó una validación con una red de prueba y los resultados fueron satisfactorios, obteniéndose errores con una desviación menor a los arrojados por la metodología actual. Los resultados también validaron la hipótesis de que es posible conocer las pérdidas de una región de la asignación a los agentes participantes de la misma.

La metodología fue aplicada con información real de sistema español para el mes de enero de 2013 para demostrar el proceso que se debe llevar a cabo. Se obtuvo una ecuación de pérdidas considerando la demanda, generación, flujos desde transmisión, importaciones y exportaciones en distribución. Los resultados mostraron coherencia con respecto al efecto de la generación distribuida y las cargas conectadas en baja tensión. Se encontraron similitudes con los resultados obtenidos aplicando el prorrateo y los coeficientes de pérdidas estándar.

La tesis reflejó la necesidad de que el DEI tenga acceso a la información de los flujos entre transmisión y distribución, con el fin de obtener directamente las pérdidas de transmisión por región y porque ser un insumo para la metodología propuesta.

Acknowledgement

First of all I have to thank to the one that makes it all possible: God. Despite of all the difficult moment that I had to overcome, I can say that this opportunity to do my master's degree in Madrid is one of the most rewarding things that I have done in my life.

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I have to give a special mention to Manuel Balmaceda at the Instituto Costarricense de Electricidad, who believed in me and sponsored my initiative to come to study to Universidad Pontificia Comillas. I also want to thank to my colleagues at Proceso Expansión de la Red for being the best co-workers.

It fulfills me with great satisfaction to look back to this last year and realize about all the great people that I met and who gave me wonderful moments. I was privileged to have an excellent group of classmates to share not only in the academic matters but also in the spare time.

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1 Introduction

1.1 Background

The Electric Power Industry as an economic activity who trades electricity as a commodity has to deal with two kinds of losses: those related to the physical characteristics of the transmission and distribution networks, typically known as technical losses, and those related to the not metered consumption of electricity that has its main roots in the stealing of electricity, mostly known as commercial losses, unaccounted-energy or non-technical losses.

Every energy transportation process has inherently losses associated that results into heat dissipation. Technical losses in the grid are produced by the conduction of electricity current through all the transmission devices employed to deliver the electricity from the source to the final consumption that are primarily lines and transformers.

Power losses P in transmission and distribution lines are in a square relation with the current in what is called “ohmic losses” and can be represented with $P = I^2R$, being R the physical resistance of the conductor and I the current going through the conductor. In this way it can be seen that losses are always related to real power. Lines also present leakage losses in the insulators in what is called the “corona effect” and is in square relation to the voltage V and in proportion to the conductance G of the insulator, and can be formally represented by the expression $P = GV^2$.

In transformers, losses are composed by a component of variable losses and a component of fixed losses. The variable losses are a function of the load applied to the transformer and are due to the resistance of the winding conductors and are known as “copper losses”. The fixed losses are losses in analogy to lines, in proportion to the square of the voltage, and due to the excitation current, called as “iron losses”.

Regarding the commercial losses, their values tend to be negligible in developed countries, but in developing countries the values can be greater than 20% in relation to the total energy (World Bank, 2009). The electricity theft will always occur at distribution levels, thus being a matter of concern of distribution utilities.

The transmission and distribution networks are composed by thousands of kilometers of conductors, making the ohmic losses the dominant cause of losses in the electric system. In this way, the energy injected from generators has to be increased to reach the final consumers, taking into account that technical and electrical losses will occur in the middle. Since electricity

cannot be stored, the energy balance that has to be accomplished in every instant is therefore $G = D + L$, meaning that generation equals the final demand and the losses.

In Spain, the electricity sector framework is structured with an unbundling of the activities of generation, transmission, distribution and retailing. Generation and retailing are open to free competition while transmission and distribution are regulated monopolies. The market operation is in hands of an independent entity called Operador del Mercado Ibérico de Electricidad (OMIE), while the system operation is in charge of Red Eléctrica de España (REE). The system operation follows a structure of integration with transmission under the scheme of Transmission System Operation (TSO), meaning that REE is the owner of all transmission assets in the Spanish system, do the planning, operation and maintenance. REE is the market participant that is in charge of guaranteeing the instantaneous meeting of the demand and generation in every moment, coping at the same time the reliability of supply.

The distribution activity is executed by more than 300 companies (Distribution System Operators, DSOs), where only 5 of them distribute energy to more than 100 000 clients and are: Iberdrola, Endesa, Unión Fenosa, Hidrocantábrico and Electra de Viesgo. The remaining distributors usually develop their activity in the lower voltage levels in reduced areas.

The typical average values for the transmission and the distribution levels for several European countries are presented in the following table in percentage of produced energy:

Table 1 Transmission and distribution losses for several European countries (ERGEG, 2008)

Country	Transmission	Distribution
Austria	1.5	4.5
Czech Republic	1.5	7.0
Finland	1.6	4.7
France	2.3	5.0
Greece	2.4	6.8
Hungary	1.4	9.2
Norway	1.6	5.0
Poland	2.1	11.8
Portugal	1.1	6.4
Romania	2.6	13.5
Slovakia	1.0	8.3
Spain	1.2	7.1
Sweden	2.1	2.3
United Kingdom	1.6	6.0

The electricity grid in Spain has a configuration that consists in a highly meshed high voltage transmission network that belongs to REE, then a subtransmission network in high voltage that can be radial or meshed and radially operated circuits in the medium and low voltage levels that belong to the distribution companies. Loads and generators can be connected in the different voltage levels.

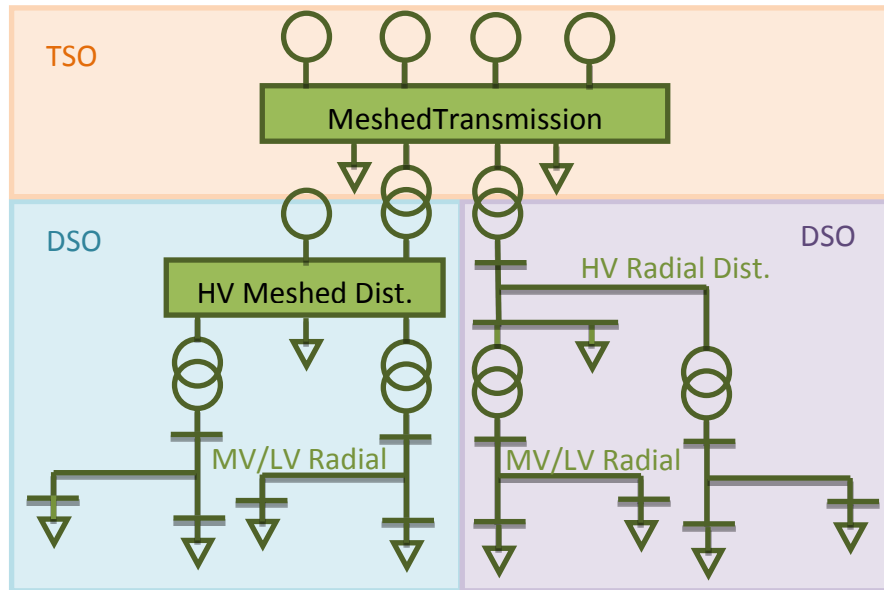


Figure 1 Configuration of Spanish Grid

For regulatory purposes, the power system has been simplified in 5 tariff voltage levels, used for the remuneration of the transmission and distribution activities. Many of the information reported by grid companies tend to follow the tariff classification. NT4 classification is a matter of the TSO while the rest of the levels are managed by the distribution companies (CNMC, 2014).

Table 2 Tariff voltage levels (CNMC, 2014)

Tariff voltage level	Range
NT4	>145 kV
NT3	>72.5 kV and <145 kV
NT2	>36 kV and <72 kV
NT1	>1 kV and <36 kV
NT0	<1 kV

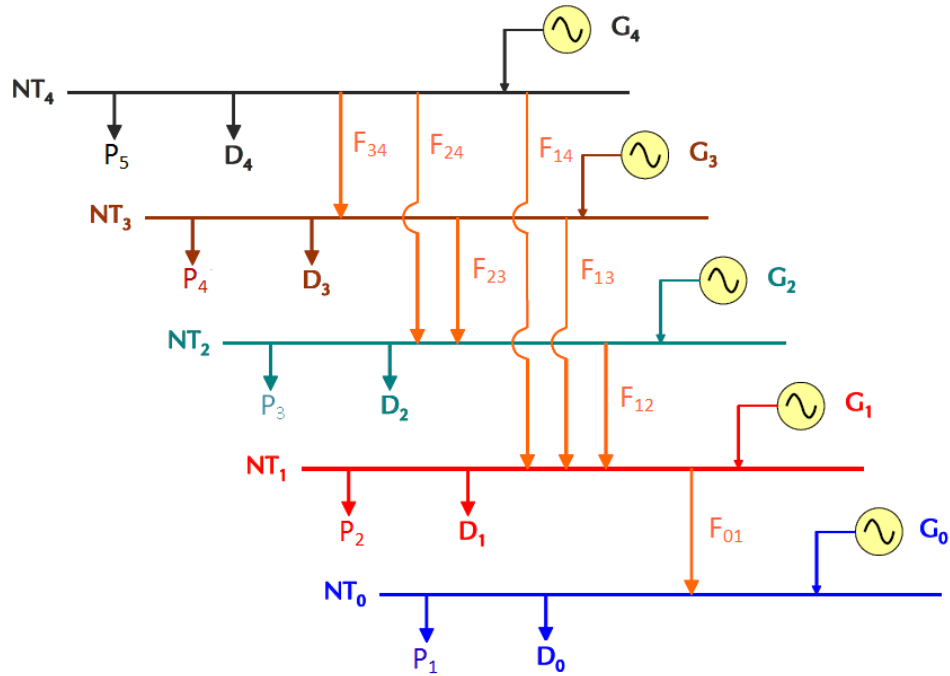


Figure 2 Simplified network model (CNMC, 2014)

1.2 Motivation

REE, being in the middle of all agents of the market is responsible for managing and publishing many of the information required not only for him but also for the planning and operation of the rest of agents. As a system operator, REE handles databases regarding the energy and power from generators and consumers, the energy mix, peak demand, demand growing, international interchanges, energy prices, network constraints, reserves (primary, secondary and tertiary), deviations and availability indexes.

The Department of Statistics and Information (DEI) of REE, is in charge of publishing this information through the Monthly Bulletin and the Electricity System Annual Report in a national basis. DEI is also working on presenting information of the electricity system to stakeholders by geopolitical regions, known as Autonomous Communities (CCAA), with the intention to cross the information with other indicators for economic and political analyses. Currently, DEI does the monthly and annual energy balance per CCAA for internal purposes, not being publicly published at the moment (DEI-REE, 2014). The monthly demand per CCAA is delivered to the Department of Grid Access for the computation of the quality of service indicators and for the presentations done to the CCAA.

The problem is that many of the necessary data is available definitely 10 months after (market settlement) but the balance has to be done the month after $m+1$. To overcome this flaw, some estimation has to be done until the definite information is accessible and consequently

updated. A methodology has been developed to compute the energy balance per CCAA with the available information (DEI-REE, 2014).

From current procedures, final consumption of users per region with a measurement point types 1 and 2¹ are known in month+1 while the definite consumption types 3, 4 and 5 are received in month+10. In this way, the energy balance is done from an estimation of the final demand from consumer types from 3 to 5 from historical data.

Total generation and pumping consumption for hydro generation per region is given information.

Since the total demand has to be equal to total generation, final consumption and losses have to be aggregated. DEI has no access to losses data in the distribution and transmission levels on a regional basis, so these values are also estimated. The actual procedure consists in calculating the total system losses from the difference between final demand and generation and then assigning the losses to each region as a weighted average of the corresponding demand. Transmission losses are also an input, so the allocation in transmission is executed with respect to demand connected at this level whereas distribution losses per region are respectively allocated with its demand.

$$L^S = G^S + IE^S - PD^S - D^S \quad (1)$$

$$L_D^S = L^S - L_T^S \quad (2)$$

$$L_T^{AC} = \frac{D_T^{AC}}{D_T^S} L_T^S \quad (3)$$

$$L_D^{AC} = \frac{D_D^{AC}}{D_D^S} L_D^S \quad (4)$$

Where,

D_T^{AC} Demand connected to transmission per autonomous community

D_D^{AC} Demand connected to distribution per autonomous community

L_T^{AC} Transmission losses per autonomous community

L_D^{AC} Distribution losses per autonomous community

D^S Final system demand

L^S Total system losses

G^S Total system demand

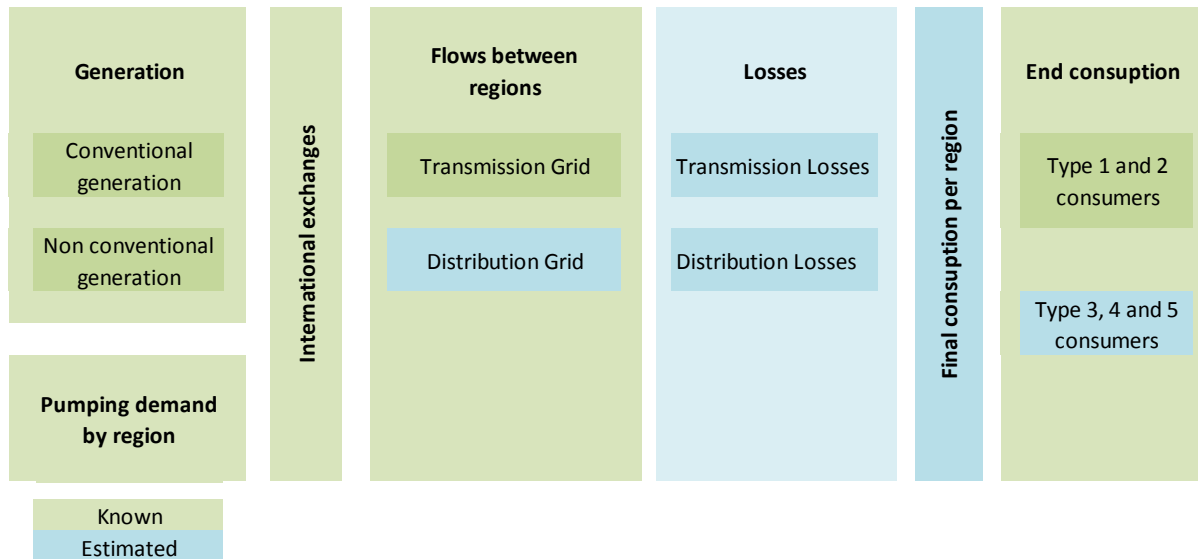
PD^S Total pumping demand

IE^S International Exchange

¹ Explanation about the different types of consumers can be found in Real Decreto 1110-2007.

The following chart summarizes the access to information to DEI for month+1.

Table 3 Known and estimated data for CCAA computations in DEI (DEI-REE, 2014)



It is important to remark that at present (also for month+1), DEI knows the voltage level connection for loads but not for all the generation. Some additional information that is also unknown is the energy flows between distribution voltage levels, and the flows among regions at the distribution level.

DEI has assessed the possibility to deal with the estimation employing other methodologies like use of standard losses and using forecast models. Standard losses are used for retailers to allocate a certain quantity of losses to the energy they buy in the market. DEI applied these coefficients and discarded their use after demonstrating that their use can diverge when validating with historical data. The forecasting model has the drawback that has insufficient information available to get results with high certainty. On the other hand, estimations of distribution losses using this method threw results with an error of 16% (DEI-REE, 2014).

After having this panorama of the problematic around the energy balance per region, it can be seen that the estimation of the distribution losses are a main concern. Moreover, the current methodology ignores the effect of neither the location of load among the different distribution voltage levels nor the impact of the distributed generation. This is something that should not pass by, since the lower voltage levels tend to have higher losses than the rest, whilst the participation of distributed generation can have a reducing effect on losses. The present thesis proposes to deal with this issue and at the same time, to geographically allocate the losses by autonomous communities.

1.3 Objectives

The main objective of the present thesis is to allocate the distribution losses of the electric system among geopolitical regions using the available information to the Transmission System Operator.

As secondary objectives, it was proposed to:

- Analyze the information published by the different market participants that can be useful for the allocation of losses at the distribution level.
- Research about the different methodologies for the allocation of losses and determine the most appropriate to be applied.
- Propose a more detailed methodology that considers the location of the demand and generation at the different voltage levels.

2 State of the art

2.1 Methods for the allocation of losses

The geopolitical allocation of losses is a topic that has not been tackled in the technical literature. The main reason has to be with the fact that there is not a standardized form of dividing countries among geopolitical regions. Usually, economical indexes for the whole country and their regions are correlated with national values of the electricity sector like the demand growing.

The more obvious answer to solve the problem could be to measure the energy that flows between regions and obtain it as the difference of outflows, inflows, generation and demand. The true is that despite the quick technological changes and the propagation of Smart Grids, the measure of electrical variables per line at the distribution level is still scarce. At the transmission level, all lines have power flow measuring capabilities, but in distribution grids the high amount of assets make it not economically feasible.

It also happens that a certain region can be served by more than one Grid Company, for example a transmission company and 2 or more distribution companies, therefore the management and coordination is not easy and requires regulation to oblige the stakeholders to deliver the information to other agents or to a centralized entity.

Having this explained, the thesis will be developed under the assumption that the losses that physically are located in a region are approximately equivalent to the losses that can be imputed to the generation, demand and interchanges in that region. In this sense, the theory to develop will be around the allocation of losses.

In (Conejo, Arroyo, Alguacil, & Guijarro, 2002) and (De Oliveira & Ponce de Leão, 2005) summarizes in groups the main techniques that are employed to allocate the losses to the grid users:

1. Pro-Rata
2. Tracing based
3. Marginal
4. Circuit based

Some of the methods require to do a two-step allocation, in which losses allocation are done with respect to the demand and then from the point of view of the generation. The theoretical assigning to both of them have to be in a 50-50 relation since generation is as responsible of

losses as the demand. It is a common practice to allocate losses completely to the demand or a major part of them (INOGATE, 2012) because of several reasons:

- Loads are mostly located in the lower voltage levels where losses are higher.
- Consumers have low elasticity, so losses variation can be hedged by demand

It is also believed that losses have to be allocated completely to generators, since they are the only one that can react to prices and place their plants in locations closer to demand to reach greater system efficiency (Gómez Expósito, 2002). This can be useful from an economical point of view to bring signals to agents, but can discourage the investment in renewable energy, which are usually far from demand.

From a geopolitical point of view, it is not important to send signals beforehand because the actual problem is to allocate ex-post result based on the location of the networks. This implies that generation has the same responsibility to reach the demand and the other way around.

The main issue with the allocation of losses to loads and generators is that for all the methods, the final allocation always contains some arbitrariness. The reason is that losses are a nonlinear function of the bus power injections that makes it impossible to divide them as a sum of term, one of each attributable per agent (Conejo, Arroyo, Alguacil, & Guijarro, 2002). To understand this statement, let's analyze the losses of a specific line with a resistance R and a transaction between two agents consuming real power P_i and P_j , the total losses $P_{L_{ij}}$ will be:

$$P_{L_{ij}} = R(P_i + P_j)^2 = R(P_i^2 + P_j^2 + 2P_iP_j) = RP_i^2 + RP_j^2 + 2RP_iP_j \quad (5)$$

It makes sense that the terms RP_i^2 and RP_j^2 can be allocated respectively to the agents at both sides, but it is not clear how to allocated the mutual term $2RP_iP_j$.

The different allocation methods will be explained in the present chapter.

2.1.1 Pro-Rata

It is the easiest method to apply and understand. It consists in allocating losses as a weighted average of their participation in the total system consumed or generated. It implies that an imputation has to be done to the demand and other to generation and then a 50-50 proportion is distributed to each one. The Pro-Rata method is also known as Postage Stamp Method (De Oliveira & Ponce de Leão, 2005).

$$L_{Gi} = 0.5 \frac{G_i}{G_T} L_T \quad (6)$$

$$L_{Di} = 0.5 \frac{D_i}{D_T} L_T \quad (7)$$

Where,

L_{Gi}	Losses allocated to load i
G_i	Energy generated by generator i
G_T	Total energy generated
L_T	Total system losses
L_{Di}	Losses allocated to load i
D_i	Energy consumed by demand i
D_T	Total demand

It can be noted that losses allocated to agents are always positive, so it is assumed that a generator or a demand cannot have a decreasing effect on losses. The simplification has the inconvenient that ignores the effect of the network. In real power system, most of the losses are present in the lower voltages, where currents and resistance are higher. Thus, a region with more clients connected to the lower voltages will produce more losses and is passed by with the postage stamp method.

The way to overcome this flaw in some power systems has been to split the different consumers in zones that will have a similar losses behavior, by having 5 levels:

- Transmission system.
- Transformation for transmission to medium voltage distribution.
- Medium voltage distribution.
- Transformation from medium voltage distribution to low voltage distribution.
- Low voltage distribution

A loss coefficient is determined for each zone and then losses imputed to consumers are a weighted averaged in its zone multiplied by the loss coefficient in its zone and upwards. To determine the coefficients, power flows are used to calculate the losses for different scenarios with typical load curves. Fixed losses in the transformation stages are calculated from the essay tests of the equipment (Eguia, 2007).

2.1.2 Tracing based

The tracing method was formally proposed by (Bialek, 1996) and is intended to be an allocation based on the topology, that doesn't require the use of power flows and is not affected by the necessity of choosing a slack bus.

The hypothesis developed is to assume that nodal inflows are shared proportionally between the nodal outflows and this allows one to trace the flow of the electricity in a meshed network. Consequently, it is possible to see the share of the flow coming from a generator to a load that is going through a line. The requirement for the input data is that Kirchhoff's Law must be

satisfied for all the nodes of the network. This implies that losses allocated will be identical to the real losses, so a reconciliation process is not necessary as in the marginal method that will be further explained.

The method can only allocate losses to generation or to demand, so two-step application has to be done assigning 50% of losses to generation and the remaining to demand. The starting point is a power flow, then losses are allocated to generation using a downstream algorithm and then to demand by using an upstream algorithm.

For the downstream process, the total gross generation in each node is the sum of the generation in each node plus the respective losses. The gross generation has to be equal to the demand in the respective node and the flow that is going to the rest of the nodes that are connected to it.

$$P_i^{gross} = P_{Di} + \sum_{j \in \alpha_i^d} \delta_{ji} P_j^{gross} \quad (8)$$

Being,

P_i^{gross} gross power injected in node i

P_{Di} demanded power in node i

δ_{ji} percentage of the flow in line ij imposed by the gross power injected in node j

α_i^d group of nodes that receive power from node i

The percentage δ_{ji} in unitary terms is calculated as

$$\delta_{ji} = \frac{P_{ji}^{gross}}{P_i^{gross}} \approx \frac{P_{ji}}{P_i} \quad (9)$$

Where,

P_{ji}^{gross} gross flow in line ji

P_{ji} real power flow injected in line ji

P_i real power flow injected in node i

The system of linear equations can be represented in matrix form:

$$A_u P^{gross} = P_G \quad (10)$$

Then the gross generation P_{Gi}^{gross} in node i can be expressed as a combination of the real demand consumed by demands.

$$P_{Gi}^{gross} = \frac{P_i^{gross}}{P_i} P_{Gi} = \frac{P_{Gi}}{P_i} \sum_{j=1}^n [A_{d,ij}^{-1}] P_{Dj} \quad (11)$$

Then the losses can be assigned to every generator from the difference between the real and the gross generation, and a coefficient c_{LGi} can be estimated in terms of the real injection.

$$L_{Gi} = P_{Gi} - P_{Gi}^{gross} = c_{LGi} P_{Gi} \quad (12)$$

$$c_{LGi} = \frac{P_{Gi} - P_{Gi}^{gross}}{P_{Gi}} \quad (13)$$

Now that the allocation has been done to generators, the second part of the method requires allocating the losses from the point of view of the demand by using a downstream algorithm. The methodology follows the same principles but this time a coefficient for the allocation to demand is calculated.

$$c_{LDi} = \frac{P_{Di} - P_{Di}^{gross}}{P_{Di}} \quad (14)$$

2.1.3 Marginal based

The marginal allocation method has its origin from the economic marginal theory to efficiently assign costs to agents in a market and has the intention to bring price signals to generators and demands to interiorize the losses on their energy bids.

An application of the method in a distribution network with embedded generation is developed in (Mutale, Strbac, & Jenkins, 2000).

The marginal loss coefficients (MLC) describe the marginal change in total active power losses L as a result of a marginal change in consumption or generation of active power P_i and reactive power Q_i in every node of the grid.

$$\tilde{\rho}_{P_i} = \frac{\partial L}{\partial P_i} \quad (15)$$

$$\tilde{\rho}_{Q_i} = \frac{\partial L}{\partial Q_i} \quad (16)$$

Where $\tilde{\rho}_{P_i}$ and $\tilde{\rho}_{Q_i}$ the active and reactive power sensibilities that represent the MLC.

In load flow calculations, losses are supplied from the slack node, so the loss related charges associated to this bus are zero. This means that the total system power losses are invariant to changes in active and reactive injections or withdrawals from the slack bus.

$$\frac{\partial L}{\partial P_s} = \frac{\partial L}{\partial Q_s} = 0 \quad (17)$$

The further statement implies that the selection of the slack bus impacts in the magnitude and sign of the losses coefficients, but not their relative value. When calculating the MLC for a distribution network, the choosing of the slack node becomes simpler since the transmission connection busbar is the ideal node for the task.

MLC are dependent of a particular operating point; therefore they are different for the system condition in every hour. The MLC are obtained by applying the chain rule from the power flow equations, resulting into a set of linear equations.

$$\begin{bmatrix} \frac{\partial P_1}{\partial \theta_1} & \dots & \frac{\partial P_N}{\partial \theta_1} & \frac{\partial Q_1}{\partial \theta_1} & \dots & \frac{\partial Q_N}{\partial \theta_1} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial P_1}{\partial \theta_N} & \dots & \frac{\partial P_N}{\partial \theta_N} & \frac{\partial Q_1}{\partial \theta_N} & \dots & \frac{\partial Q_N}{\partial \theta_N} \\ \frac{\partial P_1}{\partial V} & \dots & \frac{\partial P_N}{\partial V_1} & \frac{\partial Q_1}{\partial V_1} & \dots & \frac{\partial Q_N}{\partial V_1} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial P_1}{\partial V_N} & \dots & \frac{\partial P_N}{\partial V_N} & \frac{\partial Q_1}{\partial V_N} & \dots & \frac{\partial Q_N}{\partial V_N} \end{bmatrix} \begin{bmatrix} \frac{\partial L}{\partial P_1} \\ \vdots \\ \frac{\partial L}{\partial P_N} \\ \frac{\partial L}{\partial Q_1} \\ \vdots \\ \frac{\partial L}{\partial Q_N} \end{bmatrix} = \begin{bmatrix} \frac{\partial L}{\partial \theta_1} \\ \vdots \\ \frac{\partial L}{\partial \theta_N} \\ \frac{\partial L}{\partial V_1} \\ \vdots \\ \frac{\partial L}{\partial V_N} \end{bmatrix} \quad (18)$$

The previous system of equations can be reduced to the compact form. The losses coefficients are obtained as a result of inverting the Jacobian matrix.

$$A\tilde{\rho} = b \quad (19)$$

$$\tilde{\rho} = A^{-1}b \quad (20)$$

Where,

A Jacobian transposed matrix from the Newton-Raphson power flow

$\tilde{\rho}$ vector of marginal losses coefficients

b vector of losses sensibilities with respect to angle and voltage marginal changes in nodes

The result of the application of the MLC methodology yields approximately to the double of the actual losses. This is because losses have a quadratic relationship with current.

$$\sum_{i=1}^{N-1} [\tilde{\rho}_{P_i} P_i + \tilde{\rho}_{Q_i} Q_i] \approx 2L \quad (21)$$

Consequently, coefficients have to be readjusted with a reconciliation process that requires factorizing by k , that is the ratio between the real losses and the total losses allocated with the marginal coefficients.

$$k = \frac{L}{\sum_{i=1}^{N-1} [\tilde{\rho}_{P_i} P_i + \tilde{\rho}_{Q_i} Q_i]}$$

$$\rho_i = k \tilde{\rho}_i \quad (22)$$

Where ρ_i is the reconciled losses coefficient for node i .

2.1.4 Circuit based

The circuit based method was developed in (Conejo, Galiana, & Kockar, 2001) as the Z-bus allocation method. As other approaches, this method takes a solved power flow and systematically distributes the system transmission losses P_{loss} among the buses of the network. Each node is responsible of paying for its losses, represented by L_k , in such a way that generators will see their revenue reduced whereas the demand will have to pay at the marginal price so that the pool remains neutral. Since the method can only allocate losses to nodes, a pro-rata allocation per bus is necessary to finally assign the losses to market players in the same manner that for the proportional sharing method.

For the application of the method, a solved power flow is necessary and the inversion of the admittance matrix Y to obtain the impedance matrix X . The reason for the use of the Z matrix is because losses can be directly represented from currents from the following equation:

$$P_{loss} = \Re \left\{ \sum_{k=1}^n V_k I_k^* \right\} = \Re \left\{ \sum_{k=1}^n I_k^* \left(\sum_{j=1}^n Z_{kj} I_j \right) \right\} = \Re \left\{ \sum_{k=1}^n I_k^* \left(\sum_{j=1}^n R_{kj} I_j \right) \right\} \quad (23)$$

Where

- V_k Voltage in node k
- I_k Current entering node k
- Z_{kj} Impedance between nodes k and j

Consequently, the loss component associated with bus k is represented as

$$L_k = \Re \left\{ I_k^* \left(\sum_{j=1}^n R_{kj} I_j \right) \right\} \quad (24)$$

The nodal loss L_k sums up n terms which represents the coupling between injection at all n buses with the current injection at bus k .

The Z-bus algorithm can yield to allocate negative values to reward generator or loads that can contribute to the reduction of losses. The total losses obtained with this method are equal to the real losses, so then a reconciliation process is not necessary.

2.2 Allocation of losses in Spain

The current regulation in Spain defines what is called the standard losses coefficients, which are published every year in the Royal Decree that establish the tolling for the transmission and distribution services. The losses coefficients are defined by voltage range, period and type of access point. Every customer, independently of being a free or regulated consumer, has a quantity of losses allocated through the coefficients and is applied by the retailer when the energy is to be purchased in the wholesale market.

$$E_W = E_{CP}(1 + C_L) \quad (25)$$

Where

- E_W Energy to be bought in the wholesale market
- E_{CP} Energy to be consumed in connection point to the grid
- C_L losses coefficient in percentage

In Spain, losses are allocated to consumers in a 100%, thus the coefficients are interpreted as a multiplicative factor to “elevate the demand to an equivalent generation busbar”. Since the whole losses are assigned to the demand, the effect of distributed generation to decrease or increment the distribution losses is neglected.

The losses coefficients were published by the first time in 1999 and the last time when they were published was in the Royal Decree that established the tolling for 2014. The methodology for the computation of the losses coefficients is unknown and their values have remained almost the same during all these years (Eguia, 2007).

The Royal Decree 216-2014 changed the way that losses had to be allocated in an hourly basis and gave the responsibility to the system operator in defining the computing methodology (MINETUR, 2014). The new hourly losses coefficients are published the day before in the TSO web page. The new methodology takes the standard losses collected from the Royal Decrees and applies a correction factor k_{est} to adapt them to a standardized demand curve that is constructed from average values of the year before.

Table 4 Standard losses coefficients (MINETUR, 2014)

Tariff	Allocated losses (%)					
	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6
Low Voltage Last resort consumer – no hourly discrimination	14					
Low Voltage Last resort consumer – 2 periods	14.8	10.7				
Low Voltage Last resort consumer – 3 periods	14.8	14.4	8.6			
Low Voltage Free consumer – 3 periods	15.3	14.6	10.7			
> 1 kV and < 36 kV – 3 periods	6.6	6.4	4.8			
> 1 kV and < 36 kV – 6 periods	6.8	6.6	6.5	6.3	6.3	5.4
> 36 kV and < 72.5 kV – 6 periods	4.9	4.7	4.6	4.4	4.4	3.8
> 72.5 kV and < 145 kV – 6 periods	3.4	3.3	3.2	3.1	3.1	2.7
> 145 kV – 6 periods	1.8	1.7	1.7	1.7	1.7	1.4

Table 5 Standard losses coefficients for other supply contracts

Voltage range	Allocated losses (%)
< 1 kV	13.81
> 1 kV and < 36 kV	6.00
> 36 kV and < 72.5 kV	4.00
> 72.5 kV and < 145 kV	3.00
> 145 kV	1.62

3 Method Proposal

The proposed method has to comply with several requisites:

- Easy to apply: the method will be implemented by the Department of Information and Statistics, thus in order to be useful with the existing computational tools available, the formulation has to be solved using algebraic equations without having to solve power flows.
- Lack of information: it was explained in the motivation that the main reason of this master thesis is the unavailability of information, throwing the necessity of estimating certain values. At the moment of the elaboration of the energy balance in month+1, some loads are estimated and flows interchanged between distribution voltage levels are unknown. After 10 months the energy settlement for the whole system is done, meaning that historical information can be used to estimate present values.
- Simplified model: network models are unknown and the energy balance is matched using a one-node simplification where losses are modeled as a load.
- Monthly data: DEI handles massive amounts of data. The reports delivered by the department regarding the regions are presented in a monthly basis. This implies that losses have to be estimated in terms of energy instead of power.
- Ex-post computation: the allocation has to be done after real operation. The obtained results are for statistical purposes. The energy balance has to match perfectly so generation and demand must equals to zero. Obtained values are not required to send economic efficiency signals.

The power systems follow a hierarchy of three main levels in its structure: transmission, sub-transmission and distribution. Transmission meshed grid, the higher level, is characterized of having big generation capacity plants and intensive consuming loads, connected by lines and substations easy to quantify. The distribution level has countless kilometers of lines and high amounts of low capacity loads, while the generation penetration is still low (but will become a great issue in the future). The sub-transmission radial grid is a level with less generation but higher demand than the transmission level.

Traditionally, the higher voltage levels are characterized of having great monitoring platforms. High voltage substations and transmission lines are equipped with measurement, automation, protection and communication systems that allow perfect observability. Control Center of the TSO has real time access to incoming and outgoing flows through the Supervisory Control and

Data Acquisition system (SCADA). The high investment cost, low assets quantity and enormous amounts of energy easily justify the investment in measurement monitoring systems.

The distribution system accounts for millions of assets of lower investment cost that are in constant change. Despite the Smart Grid initiatives in the last decade, the monitoring capacity in the lower voltage levels is still scarce. In Spain, the sub-transmission is in hands of the distribution companies, and is known as high voltage distribution.

Table 6 Composition and monitoring of the power system

Type	Structure	Clients	Assets	Monitoring
Transmission	Mesh	Few	Not many	High
Distribution	Sub-transmission	Several	Quite a lot	High
	MV/LV	Many	Many	Low

Spain has REE as a unique TSO for the whole Spanish transmission system and 5 major distribution companies. Distribution companies are licensed to operate in an area that does not coincide with geopolitical division, so a region can be supplied by one or more distribution companies. Apart of that, a certain region can share circuits with other regions, so feeders can be connected to distribution substations that are beyond the bounds or vice versa.

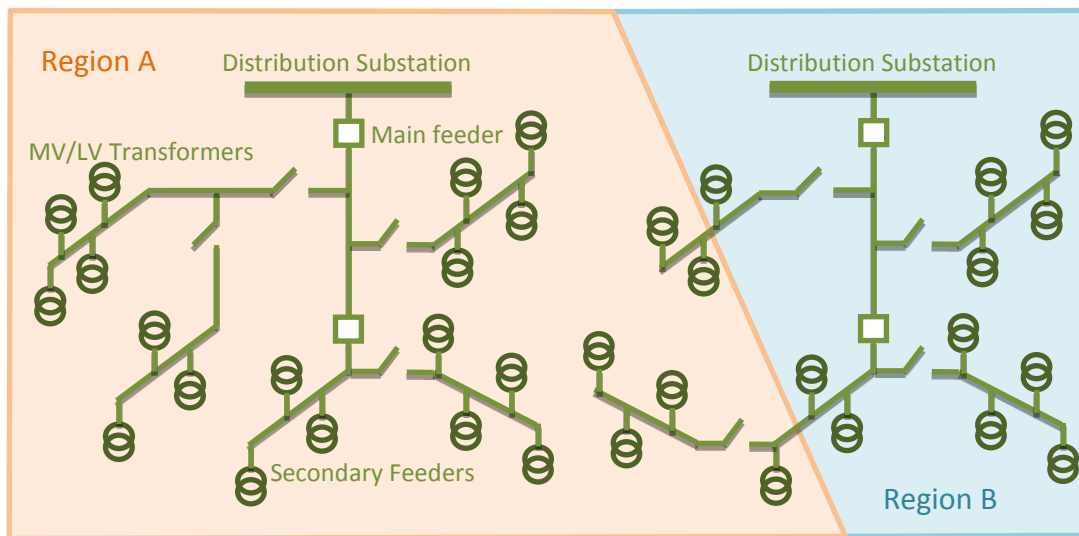


Figure 3 Circuits overlapping among regions

The overlapping of circuits among regions from different distribution companies makes it impossible to correlate the extraction from a substation with the losses of a region. Additionally, the absence of measuring devices in the distribution system complicates the direct determination from measuring of the net inflows or outflows in a region. The allocation of

generation and demand to regions do not face the same issue, because it is a common practice to have their location in the data bases with the connection documentation.

The first obvious alternative to allocate losses among regions is to measure it, but the benefits do not justify the required investment for the current cost of measurement and communication devices. This also would require regulatory provisions for the TSO to have access to that information to elaborate the energy balance by Autonomous Communities.

The second best alternative would be to model completely the power system (transmission and distribution) and run an ex-post power flow the real generation and demand to determine the flows through lines, and then determine the net inflows or outflows between regions assuming that the geographical location information of all assets is available. It is also a utopic situation since it is usual that the distribution companies do not model completely their networks because of the complexities associated to the high amount of data, the difficulties to update the model with the constant changes and the complexity to model phase unbalances in loads. This approach also has the drawback of requiring regulation to enforce distribution companies to deliver the information to the TSO.

The third best alternative is to approximate the geographical allocation of losses in accordance to methods used for the technical-economic allocation of losses. The approach has the inconvenience that the traditional allocation methods are intended to assign based on causality reasons. In a market when it is necessary to assign the losses to a market participant, the injection or extraction of energy will increase or decrease, or both, the losses in transmission lines all along the system. It is a matter of fact that always the most affected lines are those locate in the surroundings of the injection or withdrawal point. The present thesis will stand under the hypothesis that the traditional allocation methods can be used to determine how to assign the losses among regions.

The availability of information is one of the main drawbacks to do a proper allocation. The DEI do not handle network information that is key to estimate network losses and losses are modelled as load. Still there is a necessity to improve the accuracy of the energy balance with the available information. It has to be remembered that DEI works with one-node information.

The state of the art revealed four methods to do the allocation of losses: pro-rata, circuit based, marginal and proportional sharing.

The circuit based method for our purposes is impossible to be applied because it is a requirement to possess the impedance matrix.

The marginal based method requires also to model the network and to run an optimal power flow, hence it also requires to manage a marginal cost data base. The marginal approach is also discarded.

The proportional sharing method is an approach that only depends on the topology and do not require a modelling of the transmission network. It is applied after a solved power flow (or real data) where the inflow power of a line is different to the outflow to reflect the losses. The proportional sharing method traces the flows of generators and loads along the line connecting buses and assigns the losses in proportion to the net power in a node and then applying a pro-rata method to assign within the node. The difficulty for the implementation to be used is that buses are allocated line losses but the available data model losses as demand while the inflows and outflows between voltage levels have the same value but opposite sign.

The final option is the pro-rata method. The method seems to be very simple, and one may think that results can bring to under of overestimation due to the fact that the network is ignored. In many power systems like Colombia, UK, Chile, Australia and Spain, the method has been improved with the intention to bring an easy tool to allocate losses to the demand to buy them in the wholesale market or to compute the losses incentives (Acero, 2010). The improvement consists in obtaining losses coefficients that depend on the voltage level in which the load is connected. These coefficients are obtained from power system flow simulations or simple system energy balance by voltage level from historical data. The usual manner of using the coefficients consists in multiply the demand directly by the coefficient to obtain a total demand plus losses. In other cases, the coefficient is used to calculate a factor to multiply the demand. The new aggregated demand that includes the losses has to be approximately the total system generation, independently of the voltage level where the generation is connected. Since the coefficients are based on historical data, the aggregated demand with losses never match exactly the total generation and a settlement process takes place to compensate all the energy unbalances.

The last approach seems to be the most interesting to be applied because it can satisfy all the requisites enumerated at the beginning of this chapter. But how can it possible to apply losses coefficients to allocate them among regions? The idea behind is to find some losses coefficients to multiply the known generation and demand of certain autonomous communities to do the allocation. The complete procedure is the following:

1. Obtain system losses coefficients from historical data.
2. Generation and demand for a specific autonomous community with voltage differentiation are multiplied by the system losses coefficients to obtain the region losses with the losses equation.

3. Compute a reconciliation factor k_r to fit the computed losses with the total losses.
4. Multiply the region losses by k_{rec} .

The coefficients have the property to synthesize in a ratio the behavior of a grid to produce a defined quantity of losses in a presence of a certain value of flows going through it.

The presented method has its foundations in the following assumptions:

- All regions have a grid with similar topologies, meaning that all they have their grids with the same voltages, connected between them in the same way and with a similar share of meshed and radial circuits.
- Losses behave linear to a change in the flow.
- Networks have a negligible change from one year to the other.

3.1 Mathematical formulation

3.1.1 Computing losses coefficients

The main idea behind the method is to reflect the effect of the losses in every layer of the system, with the unique condition to satisfy the Kirchhoff Law.

It can be demonstrated that losses in a grid are proportional to the square of the demand consumed. Let's think in a demand D connected to a bus with a voltage V at the end of a radial line with a resistance R , then the losses coefficient c and the line losses will have a quadratic relation with the demand:

$$L = 3I^2R = 3\left(\frac{D}{\sqrt{3}V}\right)^2 R = \left(\frac{R}{V^2}\right) D^2 = cD^2 \quad (26)$$

For little incremental variations, the relationship between the losses and the demand is almost linear. This approximation will be helpful to provide simplicity to the mathematical formulation, but it is important to keep in mind that the coefficient are valid only for little load increments.

$$c = \frac{L}{D^2} \approx \frac{L}{D} \quad (27)$$

The procedure will consist in two steps: in a first step losses in a specific level are computed as a linear relationship to the energy extracted from a voltage level and the second step will consist in computing as the ratio between the losses in a level with the injections.

$$c_n^e = \frac{L_n}{P_n^e} \quad (28)$$

$$c_n^i = \frac{L_n}{P_n^i} \quad (29)$$

Being,

- L_n Losses in node representing voltage level n
- P_n^e Power extracted in node representing voltage level n
- P_n^i Power injected in node representing voltage level n
- c_n^e Losses coefficient for extractions in node representing voltage level n
- c_n^i Losses coefficient for injections in node representing voltage level n

It can be seen that the coefficients require having full information about losses, the injections and extractions at each voltage level, something that is not possible to have in month+1 when the regional energy balance needs to be done. The proposal is to obtain these values using the final data from the energy balance published by CNMC like the last published in (CNMC, 2014). This issue will be explained in more detail in Chapter 4. Currently, the information delivered to DEI aggregates some of the generation independently from their voltage connection point and lacks the information regarding the energy flows between voltage levels. It will not be possible to get the information of the flows in the distribution level but it is feasible to know the voltage connection for the whole generation and it could be a valuable improvement.

3.1.2 The losses equation

The losses equation consists in an expression to obtain the losses of a region based on historical losses coefficients multiplied by generation and demand in different voltage levels. Every topology will have its own losses equation, thus in order to demonstrate the logic behind the formulation, an example with 3 layers will be developed, where each layer represent the high, medium and low voltage.

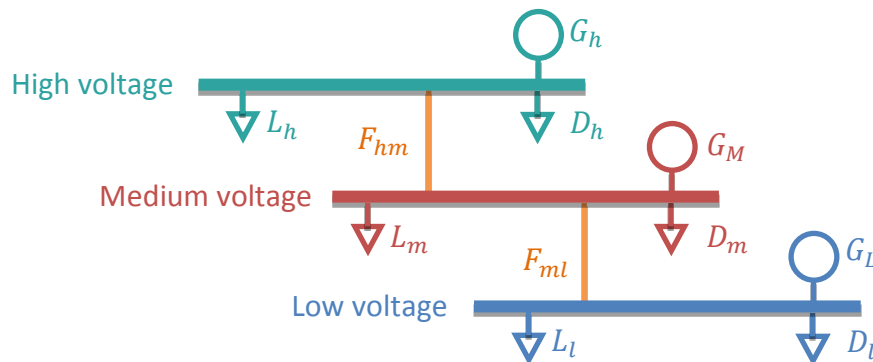


Figure 4 Simplified 3 layers model

A balance equation is formulated for each voltage level:

$$G_h - F_{hm} - D_h - L_h = 0 \quad (30)$$

$$G_m + F_{hl} - F_{ml} - D_m - L_m = 0 \quad (31)$$

$$G_l + F_{ml} - D_l - L_l = 0 \quad (32)$$

Where

G_n is the generation connected to the equivalent node in high H , medium M or low L voltage

D_n is the demand connected to the equivalent node in high H , medium M or low L voltage

F_{nm} is the flow between two equivalent nodes high-medium HM or medium-low ML

Losses are formulated as a proportion of extractions using the respective losses coefficients:

$$L_h = c_h^e (F_{hm} + D_h) \quad (33)$$

$$L_m = c_m^e (F_{ml} + D_m) \quad (34)$$

$$L_l = c_l^e D_l \quad (35)$$

Losses expressed in terms of the losses coefficients are substituted in the balance equations for each node and a unique balance equation is obtained for the whole system:

$$G_h + G_m(1 + c_h^e) + G_l(1 + c_h^e)(1 + c_m^e) = D_h(1 + c_h^e) + D_m(1 + c_h^e)(1 + c_m^e) + D_l(1 + c_h^e)(1 + c_m^e)(1 + c_l^e) \quad (36)$$

In order to obtain a simplified expression, aggregated coefficients k are introduced and the elements of the formula are regrouped:

$$(1 + k_h^e) = (1 + c_h^e) \quad (37)$$

$$(1 + k_{hm}^e) = (1 + c_h^e)(1 + c_m^e) \quad (38)$$

$$(1 + k_{hml}^e) = (1 + c_h^e)(1 + c_m^e)(1 + c_l^e) \quad (39)$$

$$G_h + G_m + G_l = D_h + D_m + D_l + [(D_h - G_m)k_h^e + (D_m - G_l)k_{hm}^e + D_l k_{hml}^e] \quad (40)$$

The last term in square brackets correspond to the total system losses for the simplified model. The coefficients k_h^e , k_{hm}^e and k_{hml}^e can have a physical interpretation of "bringing the extractions to the high voltage node". The losses equation for the extraction:

$$L^e = (D_h - G_m)k_h^e + (D_m - G_l)k_{hm}^e + D_l k_{hml}^e \quad (41)$$

The second step consists in calculating the losses as a function of the injections to the nodes.

$$L_h = c_h^i G_h \quad (42)$$

$$L_m = c_m^i (G_m + F_{hm}) \quad (43)$$

$$L_l = c_l^i (G_l + F_{ml}) \quad (44)$$

Now the aggregated coefficients represent a way to “bring the injections to the low voltage node”.

$$(1 - k_{hml}^i) = (1 - c_h^i)(1 - c_m^i)(1 - c_l^i) \quad (45)$$

$$(1 - k_{ml}^i) = (1 - c_m^i)(1 - c_l^i) \quad (46)$$

$$(1 - k_l^i) = (1 - c_l^i) \quad (47)$$

The result from this second step is the losses expression represented with injection coefficients.

$$L^i = (G_l - D_m)k_l^i + (G_m - D_h)k_{ml}^i + G_h k_{hml}^i \quad (48)$$

The generalized expression to obtain the unreconciled losses L^{ur} as a function of historical coefficients and the actual generation and demand of a region is the average of the losses using both the injection and the extraction coefficients.

$$L^{ur} = \frac{L^e + L^i}{2} \quad (49)$$

$$L^{ur} = \frac{1}{2} [(D_h - G_m)k_h^e + (D_m - G_l)k_{hm}^e + D_l k_{hml}^e + (G_l - D_m)k_l^i + (G_m - D_h)k_{ml}^i + G_h k_{hml}^i] \quad (50)$$

3.1.3 Reconciliation factor

The losses obtained for a region are an approximation given the assumption that coefficients are obtained from past values. When elaborating the energy balance for the autonomous communities, the total generation, demand and losses are known for the whole system. The total system losses must be equal to the total estimated losses calculated from the coefficients times a reconciliation factor k_{rec} .

$$k_{rec} = \frac{L_{real}}{L_{ur}} \quad (51)$$

Where

L_{real} Real total system losses

L_{ur} Estimate unreconciled total losses using coefficients.

Finally the expression to compute the total or the regional losses can be done through the following equation:

$$L = k_{rec} L_{ur} = \frac{k_{rec}}{2} [(D_h - G_m)k_h^e + (D_m - G_l)k_{hm}^e + D_l k_{hml}^e + (G_l - D_m)k_l^i + (G_m - D_h)k_{ml}^i + G_h k_{hml}^i] \quad (52)$$

3.2 Method validation

The methodology proposed here cannot be validated with real data due to the fact that it is impossible to measure the flow interchanges at all voltage levels in the grid. It was explained before that the cost for a utility to install measurement systems considering the actual cost of the technology do not justify the benefits of the investment. Neither the information is enough to model properly the distribution system. The best option to assess the feasibility of the proposed method is to do the validation with a test system.

The test system consists in a theoretical power system from an own elaboration based in documented networks obtained from the literature for simulation purposes. The idea is to arbitrarily divide the test system in regions to obtain the real losses for each region and apply the proposed methodology to it to verify its accuracy and compare it with the current methodology applied by DEI.

The validation process has the following stages:

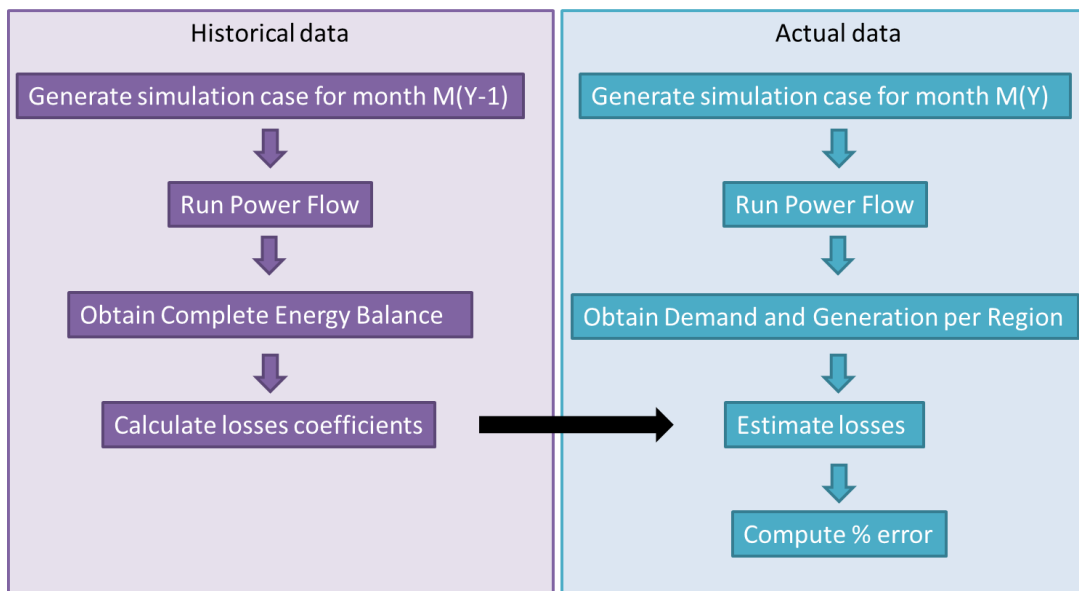


Figure 5 Diagram for validation process

The validation has to be a recreation of how should it be in reality. In this sense, a full energy balance is obtained from historical information by building a case that is supposed to reflect a system condition a year before for the same month. Since it represents a past moment, all information is known with certainty and all agents have delivered their information to obtain a final system settlement. Losses coefficients and aggregated losses coefficients are computed to be used in the actual month when the losses are required to be estimated. A current year simulation case is built, and power flows are run to obtain the generation and demand that fulfills the system. It is supposed that in a present situation for month M, losses per voltage

level and flows between levels are unknown and the only available data is the generation and demand for each voltage level. Then losses are estimated with the help of the historical coefficients for the proposed approach and the pro-rata methodology currently applied by DEI for comparison.

The proposed methodology considers weighting 50% to extractions and 50% to injections, while the DEI methodology computes losses with 100% to demand (extractions). All possible combinations of demand and generation (100% extractions, 100% injections, 50/50 extractions and injections) are assessed to demonstrate the impact in accuracy of the results. In total, losses are estimated using 6 possible approach combinations, based in the weight given to demand and generation:

Table 7 Assessed approaches

Approach	Extractions	Injections
A. Pro-rata	100%	0%
B. Pro-rata	0%	100%
C. Pro-rata	50%	50%
D. Proposed method	100%	0%
E. Proposed method	0%	100%
F. Proposed method	50%	50%

The percentage of error is obtained for each approach to validate the proposed methodology.

3.2.1 Test system

A theoretical test system was necessary to validate if the propose approach could give reliable results to obtain the losses for each region. The advantage of having a test system is that there is complete knowledge of all the power system variables, while in reality a lot of information is unavailable, so the validation is not possible. The validation test system was built inspired in the 230 kV transmission network of the test system presented in (Li & Bo, 2010) and the 66kV distribution network simulated in (Eguia, 2007).

Power flow simulations were executed with Matlab, with the help of Matpower package, version 5.1 (Zimmerman, Murillo Sánchez, & Thomas, 2011). Matpower is a simulation tool for researchers and educators intended for steady-state power flow and optimal power flow simulations under GNU license.

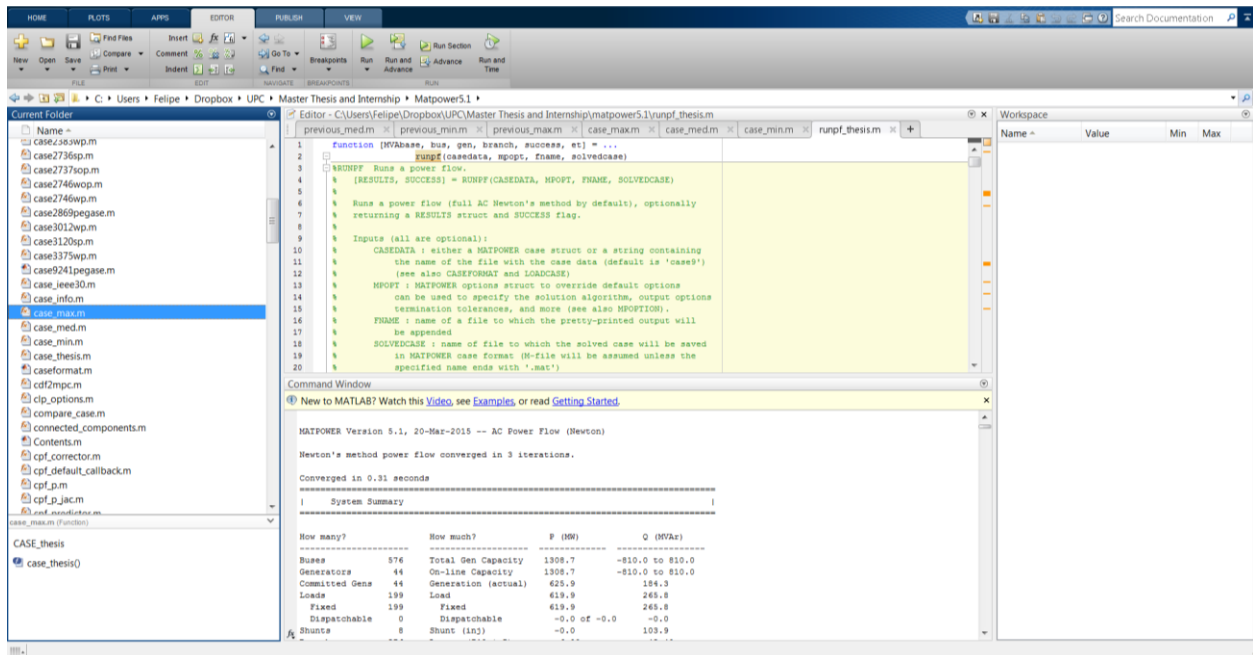


Figure 6 Software environment for Matpower in Matlab.

The base case simulation data base for month M in year Y is shown using the Matpower format in Annex 7.1. Three matrix store: branch, bus and generation. The branch matrix includes the network data modeling (resistance, reactance, and susceptance), the bus matrix models the buses (type of bus, voltage ranges) and loads (active and reactive power) and the generation matrix contains the capacity of the generation units (active and reactive power limits, power delivered and the voltage set point).

The test system network is represented in Figure 7. The system is constituted in the transmission network in 230 kV with 5 buses, 6 lines, 5 generator and 3 demands in a meshed configuration. The distribution network in 66 kV has 196 loads, 39 generators and 562 line segments (overhead and underground) in a radial configuration. The transmission and the distribution grids are connected with 3 transformers in node C and with 5 transformers in node D. A total of 18 feeders are connected to the main distribution bus in substation C, while 41 distribution feeders are connected to substation D. Voltage limits in nodes are defined in a range of +/-10 pu. Branch devices are defined with infinite capacity to facilitate the power flow convergence.

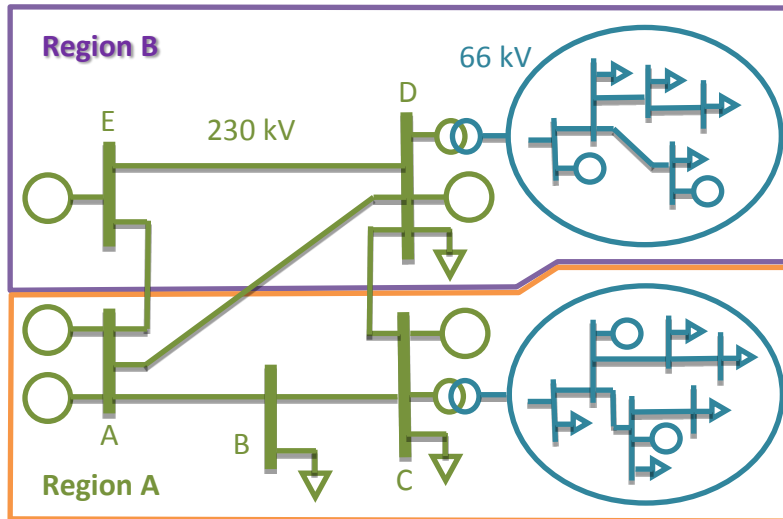


Figure 7 Test System reduced representation²

With the objective of applying the allocating methodology, the power system is divided in two regions:

1. Region A consisting in the high voltage buses A, B and C, and the distribution grid connected to them
2. Region B conformed by buses E and D, and the distribution network connected to D.

The system was designed to represent the most representative characteristics of a common power system: cheap generation is located far from load, transmission system is meshed, distribution grid is operated radial, some minor energy intensive consumers are connected to the high voltage network, and the medium voltage comprises lots of elements of demand and generation at little scale.

3.2.2 Calculating loss coefficients

Losses coefficients are obtained from a case that has a 3% less demand than the month in which losses are estimated. Current month is called $M(Y)$ to designate the current month in the present year, whereas losses coefficients are computed in the same month the year before and is called $M(Y-1)$.

² Distribution network within the circles are more complex than represented in the Figure. The illustration has the intention of showing that the network is radial with lots of elements and includes distributed generation.

The knowledge of information for $M(Y-1)$ is supposed to be completely known for each voltage level: generation, demand, losses and flow between voltage levels. The system is simplified with one node per voltage level as shown in Figure 8.

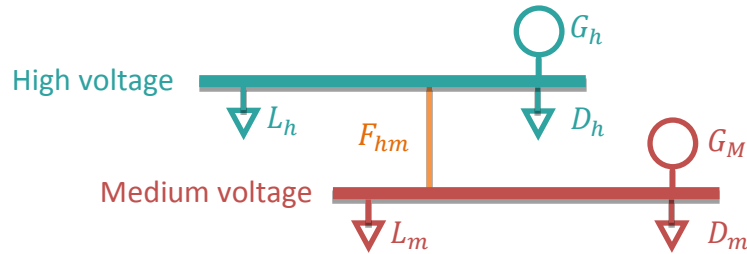


Figure 8 Simplified network representation for the test system

The monthly data is obtained from running power flows for a single day with three-period discrimination and replicated for 30 days to obtain the energy for a month. The case was built using profiles extracted from the file "Perfiles_iniciales_2015" that are published in REE website (REE, 2015). REE publishes yearly at the beginning of the year energy profiles for different kind of consumers with a normalized value for each hour which sum for the whole year is equal to one. Demands in Region A were chosen to behave as the demand profile for March 1st of 2015 and Region B to have a profile like March 31st of 2015. Profiles were adapted to unitary values and then converted to an approximation with three periods: high, medium and low demand.

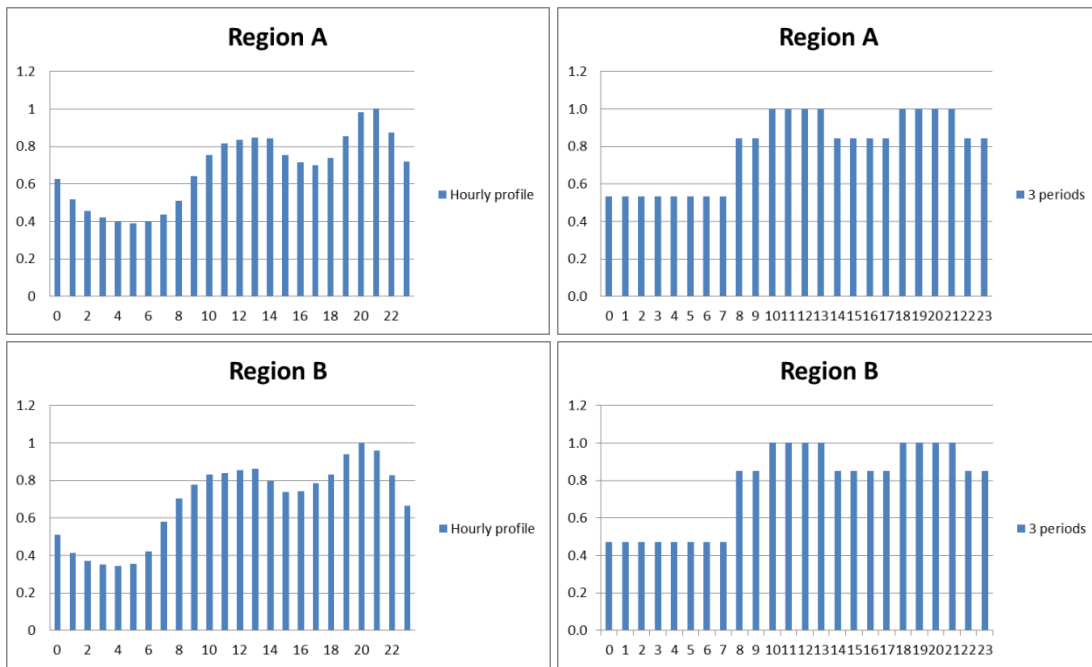


Figure 9 Three-period demand profile simplification for Regions A and B

Power flows for high, medium and low demand were run and the output from Matpower is shown in Annex 7.2. In the Matpower files, Areas 1 and 2 are Regions A and B of the transmission system; Areas 3 and 4 correspond to the geographical division of Regions A and B but this time in distribution.

The summary of the information needed to compute the coefficients is presented in Table 8.

Table 8 Energy balance per voltage level in M(Y-1)

Element	Level	Monthly energy (MWh)
Generation	Transmission	581,678
	Distribution	128,071
	Total	709,749
Demand	Transmission	273,940
	Distribution	428,030
	Total	701,970
Losses	Transmission	2,206
	Distribution	5,573
	Total	7,781
Flow	Transmission-Distribution	305,532

The computation of the losses coefficients is done following the proposed methodology and the results are shown in

Table 9 Losses coefficients for the test system

Coefficient	Formula	Value (%)
c_h^e	$\frac{L_h}{(F_{hm} + D_h)}$	0.38
c_M^e	$\frac{L_m}{D_m}$	1.30
c_h^i	$\frac{L_h}{G_h}$	0.38
c_M^i	$\frac{L_m}{(G_m + F_{hm})}$	1.19
k_h^e	c_h^e	0.38
k_{hm}^e	$(1 + c_h^e)(1 + c_m^e) - 1$	1.69
k_{hm}^i	$1 - (1 - c_h^i)(1 - c_m^i)$	1.56
k_m^i	c_m^i	1.19

3.2.3 Estimation of losses

The step taken after coefficients are computed is to estimate losses using the losses equation proposed. The base case to assess the methodology presents the same network to the one corresponding to M(Y-1) but differs in the demand, generation and losses. Demand is a 3% more than in the previous year and energy has the corresponding dispatch to satisfy the energy balance. The monthly energy was obtained in the same way that was used for the M(Y-1) case

using exactly the same load profiles shown in Figure 9. A typical day was modelled for a three-period discrimination demand curve, the value for each period was multiplied by 8 (to obtain daily energy) and then by 30 (energy in a month). From one period to the other, distributed generation was reduced in the same proportion to the demand, thus the energy balance was compensated with the slack bus.

Recreating the manner on how the losses should be calculated, it is supposed that the information available is the generation, demand per region and voltage level, and the total losses to be allocated. In reality, the power system energy balance also includes interchanges between countries, but they can be modelled as generation, when they are entering the system and as demand when they are going out.

Figure 10 Monthly energy balance for the test system

Element	Level	Region	Monthly energy (MWh)
Generation	Transmission	A	320,244
		B	283,488
		Subtotal	603,732
	Distribution	A	33,300
		B	94,771
		Subtotal	128,071
Total		731,803	
Demand	Transmission	A	171,113
		B	111,299
		Subtotal	282,412
	Distribution	A	143,317
		B	297,952
		Subtotal	441,268
Total		723,680	
Losses	Total	8,119	

Now that all the necessary data have been put down, it is time to estimate the losses. Losses are computed separately for injections and extractions for comparison purposes. The losses equations obtained from the method proposal were computed for a three-layer system; for the present exercise, the low voltage component is omitted. Equations are presented in Table 10. A reconciliation factor k_{rec} had to be computed to match the estimated losses with the total losses belonging to month M(Y).

Table 10 Losses equations for allocating regional losses of test system

Approach	Equation	k_{rec}
100% extractions	$L = k_{rec}[(D_h - G_m)k_h^e + D_m k_{hm}^e]$	1.0106
100% injections	$L = k_{rec}[(G_m - D_h)k_m^i + G_h k_{hm}^i]$	1.0681
50% extractions 50% injections	$L = \frac{k_{rec}}{2}[(D_h - G_m)k_h^e + D_m k_{hm}^e + (G_m - D_h)k_m^i + G_h k_{hm}^i]$	1.0386

Table 11 presents losses allocated to each region according to the different possible methods proposed in Table 7. A graphical representation of the results can be seen in Figure 11.

Table 11 Comparison of losses allocation among regions by several methods

Allocation approach	Region	Losses (MWh)	Error (%)
Theoretical	A	3,370	-
	B	4,750	-
A. Pro-rata 100% demand	A	3,528	4.69
	B	4,592	3.33
B. Pro-rata 100% generation	A	3,922	16.41
	B	4,197	1.17
C. Pro-rata 50/50 dem/gen	A	3,725	10.55
	B	4,394	7.48
D. Proposed 100% extractions	A	2,974	15.69
	B	5,145	12.05
E. Proposed 100% injections	A	3,597	1.96
	B	4,522	1.50
F. Proposed 50/50 inj/ext	A	3,277	2.75
	B	4,842	1.95

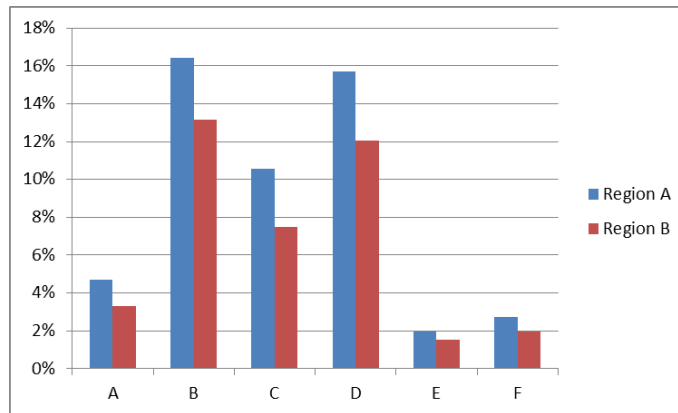


Figure 11 Percentage of absolute error in allocating losses for each approach

The approach with the most accurate result was the proposed method on 100% to injections. Nevertheless, the idea of weighting a half over demand and generation is under the principle that both are responsible of creating losses in the grid. On the other hand results demonstrate that allocating to both the demand and generation, the final result compensate the inaccuracy from one of them. From this point of view, the proposed 50/50 is more effective than the pro-rata method, having an average error of 2.75% and 1.95% in comparison to the 10.55% and 7.48% of error respectively. The least accurate method B, consisting in the pro-rata allocation 100% to generation, computing losses in region A with a 16.41% of error.

It calls tremendously the attention that the pro-rata method with respect to the demand, which is the actual method applied by the Department of Statistics and Information, is capable of bringing results with a relative high accuracy with a very simple way and in absence of lots of information.

The proposed method demonstrated to be not robust enough when computing losses from extractions, doing it with a high error (greater than 15% in region A). The main reason could be explained to the fact that coefficients proposed assume a linear variation of losses when flows in the network have an incremental variation. When applying total system coefficients to a region-wide level, the load variation can affect the results. The methodology proposed here has considered the simplicity as one of the main criteria, thus obtaining losses coefficients from a quadratic dependency could lead to marginally improve the result with a mathematical effort difficult to justify.

Despite of this, the proposed method give acceptable results and is recommended to be apply as an improvement to the methodology currently used by DEI for estimating the losses.

4 Real Case Application

Now that the validation process has been successful, is the moment to apply the methodology with real results. The present chapter has the objective to show how to follow the methodology step by step, stressing in how to compute the values with the available information.

The flowchart exhibited in Figure 12 will show the methodology to be used.

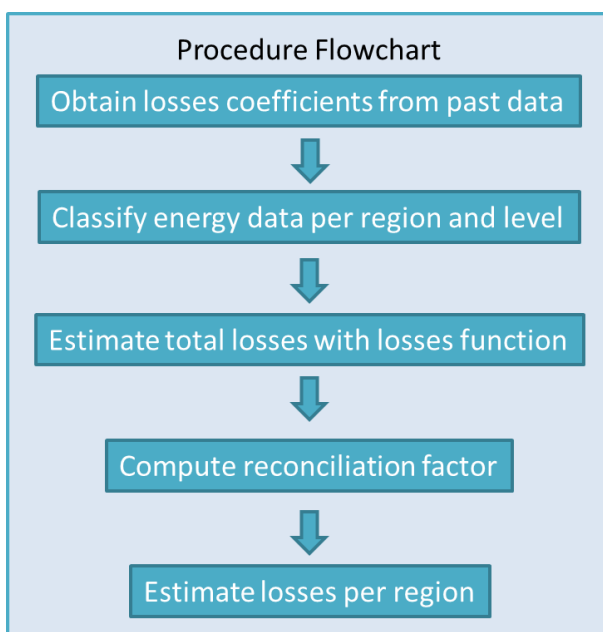


Figure 12 Flowchart for computing regional losses

4.1 Obtaining losses coefficients

To obtain losses coefficients, it is necessary to have past data with a complete energy balance for transmission and distribution. It is recommended to have this information available from the year before if possible for one main reason: the coefficients are a simple way to represent the behavior of the grid to generate losses for a given value of energy flows. The present thesis assumes as a fact that the network changes marginally from one year to the other. Investment in transmission take years to be accomplished, thus changes are slow, but at the distribution level, the grid changes more frequently and is becoming more affected everyday with the trend of Distributed Generation.

It is recommended to have in hand a balance for as many levels as possible from recent past data. This is only necessary at a system level and not per region, since it is impossible to obtain

the real data of the flows among regions at the distribution level. The energy balance has to contain the generation, demand, imports, exports, losses and flows between levels.

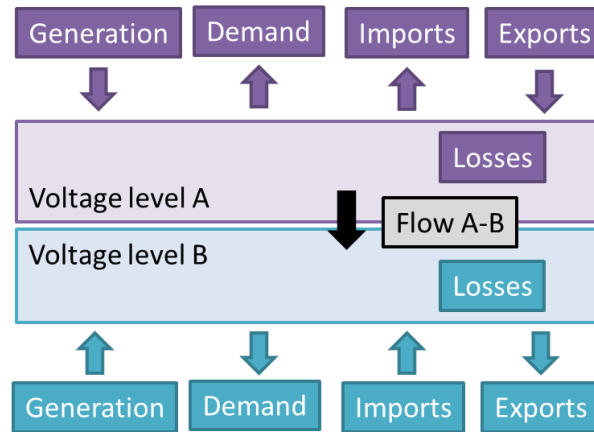


Figure 13 Necessary information to obtain losses coefficients.

After a comprehensive research of information, it was found that the only source of information that comply with the necessary information to apply the proposed methodology is generated and published by the Spanish Regulatory Authority, called Comisión Nacional de Mercados y de la Competencia (CNMC). CNMC has the obligation to generate the information that is necessary for the calculation of the tolling for the transmission and distribution services. The last document published in this sense included a complete energy balance for each regulatory voltage range. In the Spanish regulation, voltages are defined in 5 ranges (CNMC, 2014) that were explained in Table 2: NTO, NT1, NT2, NT3 and NT4.

REE-DEI has most of the information classified by voltage or at least using the voltage ranges showed before, thus making it easy to adapt the available information to that ranges. Ranges from NTO to NT3 are then used for the distribution losses allocation methodology.

All electricity customers have to pay the use of networks through the access tariff. Those tariffs consist in an energy component and a power component that are different depending on the hours of consumption. According to the type of consumers, users can be subscribe to an access tariff ranging from 1 period (without hourly discrimination) to 6 periods (MINETUR, 2014). The energy balances elaborated by CNMC are aggregate by period of consumption, and the results for Period 1 of 2012 are shown in Figure 14. The system balance include for the several voltage ranges the generation ("Generación"), demand ("Consumo"), net interchanges (labeled as REE) and losses ("Pérdidas"). Interchanges between countries are net values and all of them are considered to be injected to transmission, although some flows are interchanged in lower voltage levels, like those going to Andorra.

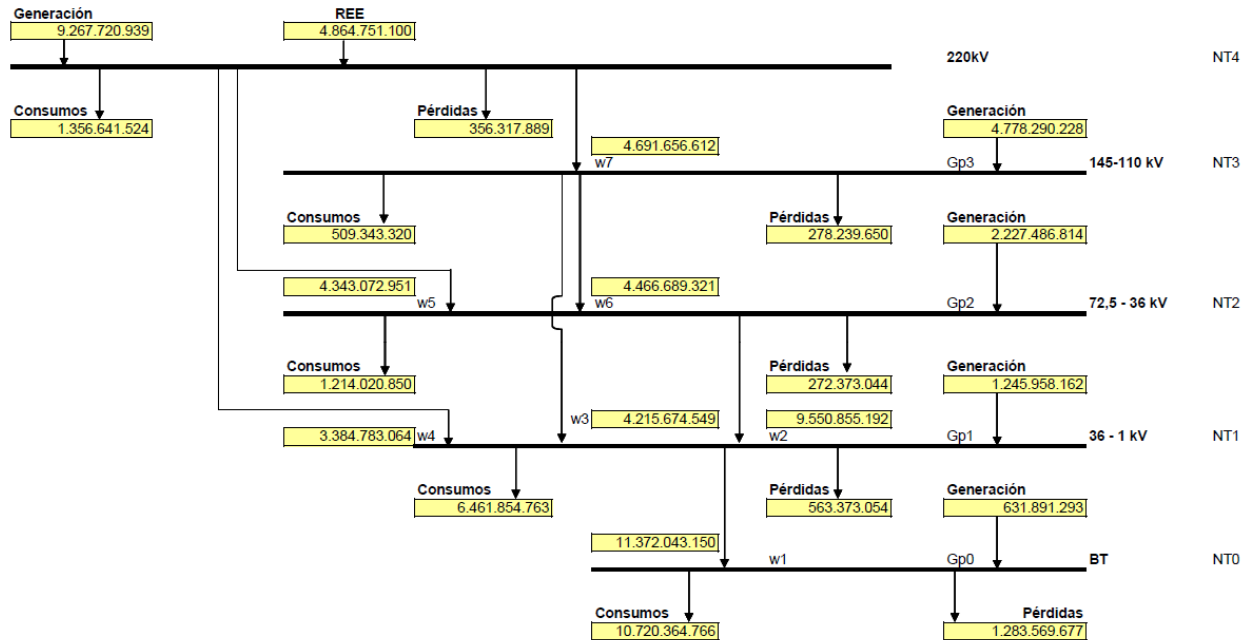


Figure 14 Energy balance (in kWh) per voltage ranges for period 1 of 2012 (CNMC, 2014)

Previous results were summed up to obtain the yearly values. It is impossible from the information available at the moment to obtain monthly coefficients. Assuming that all months have a similar behavior, the yearly value will correspond to the average of all months.

Table 12 Energy balance for year 2012 for transmission and distribution

Level	Energy (GWh)					
	Generation	Interchange	Demand	Losses	Upward flow	Downward flow
NT3	55,099.06	0.00	8,806.89	2,317.74	48,684.13	92,658.56
NT2	27,963.32	0.00	16,418.14	2,197.63	95,718.26	105,065.81
NT1	13,584.01	0.00	71,177.79	4,733.83	183,520.69	121,193.07
NT0	4,207.18	0.00	115,019.33	10,380.92	121,193.07	0.00

Losses coefficients for four layers (from NT0 to NT3) can be compute from the table before.

$$c_n^e = \frac{Losses_n}{Demand_n + Flow_{n,n-1}} \quad (53)$$

$$c_n^i = \frac{Losses_n}{Generation_n + Flow_{n+1,n}} \quad (54)$$

Subscript n stands for whichever voltage range from NT0 to NT3. The aggregated losses coefficients used in the losses equation are computed and shown in the following table:

Table 13 Aggregated coefficients

Aggregated coefficient	Value (%)
$k_3^e = c_3^e$	0.02284
$k_{32}^e = (1 + c_3^e)(1 + c_2^e) - 1$	0.04135
$k_{321}^e = (1 + c_3^e)(1 + c_2^e)(1 + c_1^e) - 1$	0.06697
$k_{3210}^e = (1 + c_3^e)(1 + c_2^e)(1 + c_1^e)(1 + c_0^e) - 1$	0.16327
$k_{3210}^i = 1 - (1 - c_3^i)(1 - c_2^i)(1 - c_1^i)(1 - c_0^i)$	0.14035
$k_{210}^i = 1 - (1 - c_2^i)(1 - c_1^i)(1 - c_0^i)$	0.12072
$k_{10}^i = 1 - (1 - c_1^i)(1 - c_0^i)$	0.10481
$k_0^i = c_0^i$	0.08278

A 4-layers losses equation is presented with regrouped terms for every demand and generation.

$$L = 1/2 k_{rec} [(k_3^e - k_{210}^i) * D_3 + (k_{32}^e - k_{10}^i) * D_2 + (k_{321}^e - k_0^i) * D_1 + k_{3210}^e * D_0 + (k_{3210}^i) * (G_3 + F_{43}) + (k_{210}^i - k_3^e) * G_2 + (k_{10}^i - k_{32}^e) * G_1 + (k_0^i - k_{321}^e) * G_0] \quad (55)$$

Note that a term F_{43} was added to represent the energy flows coming from transmission that are modelled as generation. If coefficients are substituted, the losses equation can be represented as:

$$L = k_{rec} [-0.04894 * D_3 - 0.03173 * D_2 - 0.001791 * D_1 + 0.08163 * D_0 + 0.07018 * (G_3 + F_{43}) + 0.04894 * G_2 + 0.03173 * G_1 + 0.00791 * G_0] \quad (56)$$

Losses can be decomposed as a linear combination of generation and demand in the respective voltage level. Note that the withdrawal of energy in levels NT3, NT2 and NT1 has a reducing effect on the losses. On the other hand, looking to the constant's values, the main drivers of losses are the demand in NT0 where currents and resistance of the system are higher and the generation of NT3 where generators are placed far from most of the demand.

4.1.1 Standard losses coefficients

For comparison purposes, a parallel allocation of losses among regions was done using the standard losses from the Spanish regulation that appear in Table 5. For applying them, an intermediate procedure is necessary to eliminate the component of losses of the transmission level. To do so, it is enough to do an inverse process like the one used to compute the aggregated coefficients. The values are shown in Table 14. k_3^{sl} to k_{3210}^{sl} are the losses coefficients to elevate demand losses for levels ranging from NT3 to NT0 to the transmission level. Note that generation is ignored by the use of this method.

Table 14 Standard losses for distribution allocation

Standard losses	Value
$k_3^{sl} = \frac{(1 + k_{43}^{sl})}{(1 + k_4^{sl})} - 1$	0.01358
$k_{32}^{sl} = \frac{(1 + k_{432}^{sl})}{(1 + k_4^{sl})} - 1$	0.02342
$k_{321}^{sl} = \frac{(1 + k_{4321}^{sl})}{(1 + k_4^{sl})} - 1$	0.04310
$k_{3210}^{sl} = \frac{(1 + k_{43210}^{sl})}{(1 + k_4^{sl})} - 1$	0.15654

Losses by this method are computed simply as multiplying the demand with the corresponding coefficient:

$$L_{ur} = k_3^{sl} * D_3 + k_{32}^{sl} * D_2 + k_{321}^{sl} * D_1 + k_{3210}^{sl} * D_0 \quad (57)$$

4.2 Data gathering

The second step in the methodology is to gather and classify the available information for the allocation of losses. For that purpose, DEI supplied the following monthly information for year 2013:

- Generation: data is divided in thermal plants, hydro and non-conventional generation (biomass, wind, solar, wastes and cogeneration). Data about voltage and region from conventional plants was fully supplied but some for non-conventional generation the connection voltage was unknown, therefore some assumptions were taken. It is important to stress that this was a limiting factor only for this study, but most of this information is available to REE (some minor generation still require the voltage designation). For all regions, non-conventional generation was split as follows:

Table 15 Splitting for non-conventional sources

Technology	Share (%)				
	NT4	NT3	NT2	NT1	NT0
Wind	55	27.5	12.5	5	0
Solar PV	2.5	2.5	12.5	47.5	35
CSP	65	15	7.5	12.5	0
Cogeneration	12.5	15	30	42.5	0
Others	15	25	35	25	0

- Demand with connection points classified by types (1-2, and 3-5) for each voltage level and region.
- Energy exchanges with neighboring regions and countries per voltage and autonomous community.
- Total transmission losses.

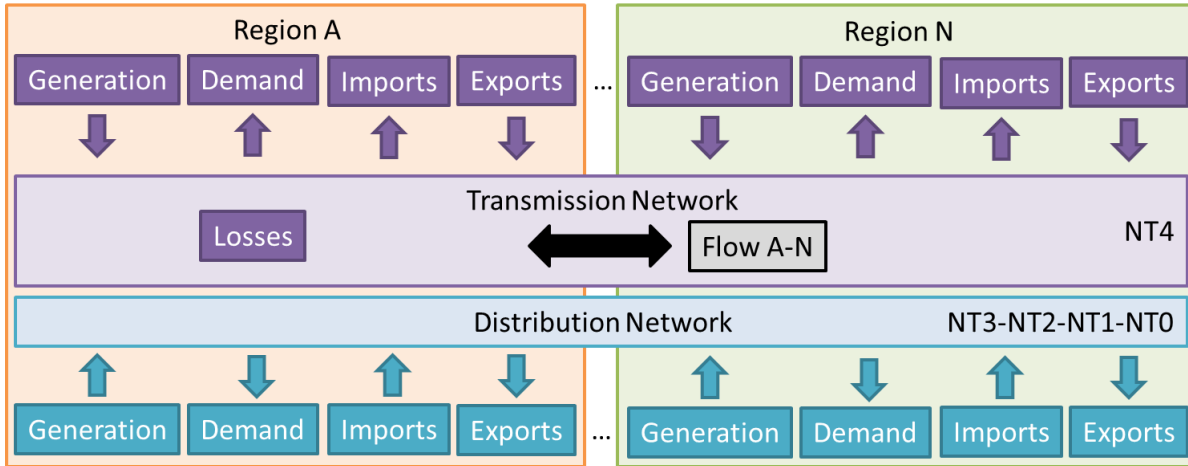


Figure 15 Information supplied by DEI

Currently DEI does not handle information about the flows between transmission and distribution so losses per region in transmission are estimated as a weighted average of its respective demand. In this way, the downstream flows from transmission to distribution per region are estimated, instead of being given directly using the aforementioned process, from the difference between generation, demand, losses and region interchanges between regions, all of them in transmission. These values are strictly necessary since losses are calculated from injections and extractions at all levels. Transmission-to-distribution flow is modelled as generation injected in the NT3 level. A first recommendation from this document is to look forward to improve the detail of the information processed by the Department of Statistics and Information of REE, since the downstream flows from transmission to distribution are known for the System Operator, in this ways accuracy with resources that can be reached easily.

For demonstrating the applicability of the proposed methodology, the month of January was chosen. The energy from generation and demand for all distribution levels can be seen in Table 16. Exports to Andorra were included as a demand in Cataluña.

Table 16 Data gathered to compute losses among regions for January 2013.

Level	Region	Energy (GWh)	
		Generation	Demand
NT3	Andalucía	359.58	65.75
NT3	Aragón	225.21	31.98
NT3	Asturias	526.70	128.35
NT3	C. Valenciana	173.79	48.68
NT3	Cantabria	30.30	13.55
NT3	Castilla la Mancha	395.93	32.92
NT3	Castilla y León	511.13	38.02
NT3	Cataluña	378.69	231.48
NT3	Extremadura	10.93	2.67
NT3	Galicia	632.25	143.84
NT3	La Rioja	35.11	0.00
NT3	Madrid	22.61	11.22
NT3	Murcia	61.46	99.74
NT3	Navarra	80.87	5.46
NT3	País Vasco	100.97	140.49
NT2	Andalucía	357.25	320.75
NT2	Aragón	196.60	97.55
NT2	Asturias	84.69	11.01
NT2	C. Valenciana	122.61	76.57
NT2	Cantabria	52.01	58.38
NT2	Castilla la Mancha	229.68	60.21
NT2	Castilla y León	311.72	251.44
NT2	Cataluña	254.81	54.16
NT2	Extremadura	14.32	17.75
NT2	Galicia	335.05	78.52
NT2	La Rioja	23.39	24.56
NT2	Madrid	41.19	154.80
NT2	Murcia	77.96	15.82
NT2	Navarra	78.41	125.80
NT2	País Vasco	83.43	0.01
NT1	Andalucía	330.15	600.96
NT1	Aragón	195.28	200.72
NT1	Asturias	58.66	128.02
NT1	C. Valenciana	114.22	743.60
NT1	Cantabria	78.78	53.12
NT1	Castilla la Mancha	178.56	256.38
NT1	Castilla y León	242.87	230.90

NT1	Cataluña	295.14	1,243.07
NT1	Extremadura	32.48	79.11
NT1	Galicia	324.01	317.88
NT1	La Rioja	18.42	37.99
NT1	Madrid	54.65	772.53
NT1	Murcia	108.07	212.67
NT1	Navarra	84.91	101.06
NT1	País Vasco	97.29	490.55
NT0	Andalucía	36.77	1,923.73
NT0	Aragón	13.16	353.00
NT0	Asturias	3.79	258.84
NT0	C. Valenciana	13.55	1,183.67
NT0	Cantabria	2.97	134.72
NT0	Castilla la Mancha	35.50	553.05
NT0	Castilla y León	22.19	621.99
NT0	Cataluña	13.75	2,067.72
NT0	Extremadura	18.16	252.78
NT0	Galicia	14.61	702.70
NT0	La Rioja	6.67	78.62
NT0	Madrid	1.91	1,581.80
NT0	Murcia	19.29	323.99
NT0	Navarra	15.11	154.69
NT0	País Vasco	2.78	541.18

A summary of results per level is shown in Table 17 and Table 18 shows the flows going from the transmission network to the distribution network.

Table 17 Summarized system energy balance for January 2013.

Level	Energy (GWh)					
	Generation	Demand	Exports	Imports	Losses	Flow Trans-Dist
Distribution	8,242.33	18,513.39	29.24	0.00	1,522.41	11,822.71
Transmission	15,399.15	2,842.44	1,518.88	1,074.85	289.97	11,822.71
Total	23,641.48	21,355.83	1,548.12	1,074.85	1,812.38	0.00

Losses represented in January of 2013 approximately an 8.5% out of total demand and can be split in 7.1% of losses in distribution and 1.4% of losses in transmission. Results show coherency with historical values contained in Table 1. Generation in the distribution grid accounted for a half of the generation in the transmission side.

Table 18 Downstream flows from transmission to distribution per region.

Level	Region	Flow Trans-Dist (GWh)
NT3	Andalucía	2442.21
NT3	Aragón	200.12
NT3	Asturias	-240.37
NT3	C. Valenciana	1,288.15
NT3	Cantabria	121.89
NT3	Castilla la Mancha	577.39
NT3	Castilla y León	495.07
NT3	Cataluña	2,742.80
NT3	Extremadura	306.37
NT3	Galicia	-20.27
NT3	La Rioja	34.68
NT3	Madrid	2,201.08
NT3	Murcia	612.53
NT3	Navarra	144.03
NT3	País Vasco	916.97

Note from the analyzed month that Asturias and Galicia regions are exporting energy to the transmission side because of the high presence of distributed generation. C. Valenciana, Cataluña and Madrid being the regions with higher population density and industry are the ones with the bigger amounts of energy taken from transmission.

4.3 Allocating Losses

Having all the information in hand, the next step is to determine the reconciliation factor for both the proposed method and for the standard losses method. It is important to remember that the losses coefficients are taken from past data and do not match the actual losses. It is necessary to determine a multiplication factor k_{rec} that can make them grow or decrease proportionally, computed as the ratio between the total real losses and the total estimated losses.

Table 19 Reconciliation factor computation

Description	Proposed method	Standard losses method
Unmatched losses (GWh)	2,002.72	1,960.80
k_{rec}	0.76	0.78

Allocation of distribution losses among regions using the proposed method is done applying equation (56) with the corrected reconciliation factor $k_{rec} = 0.76$. It can be argued that a

reconciliation factor of 0.76 represents a value with a high error with respect to the real losses for the total distribution system, but it is important to remember that the location of the non-conventional renewable resources had to be split by doing some assumptions about a convenient share of them among the different voltage levels. It very probable that having the real values the losses estimation can be closer to the real one. Despite of this, it is interesting to see that results obtained from the proposed method after the scaling of the values are similar to those resulted from other methods. One factor affecting the result can attributed to the fact that losses coefficients were obtained using annual values so they can better represent only those months behaving similar to the average.

Final results are presented in Table 20 showing the losses values computed from the proposed method and are compared with those obtained using the current methodology based in a pro-rata weight only with demand and the standard losses.

Table 20 Allocated distribution losses by region

Region	Losses (GWh)		
	Proposed	Actual	Standard Losses
Andalucía	276.52	239.02	260.45
Aragón	51.95	56.10	51.73
Asturias	30.12	43.20	37.30
C. Valenciana	150.71	168.52	170.65
Cantabria	18.10	21.33	19.36
Castilla la Mancha	95.09	74.10	77.24
Castilla y León	101.00	93.79	88.30
Cataluña	294.13	295.28	296.33
Extremadura	33.04	28.93	33.72
Galicia	87.47	102.05	98.99
La Rioja	9.14	11.59	11.27
Madrid	210.85	206.93	221.04
Murcia	56.31	53.55	47.83
Navarra	22.81	31.77	24.53
País Vasco	85.18	96.24	83.67

The three methods throw almost the same results when estimating the losses in Cataluña, were differences between the lower and the higher value are less than 1%. Cataluña is also the region registering the highest value of distribution losses with 296.33 GWh, something that is coherent with the fact of being the one with the highest demand in the power system.

Table 21 Percentage of distributed generation with respect to demand

Region	Distributed generation (%)
Andalucía	37.2
Aragón	92.2
Asturias	128.1
C. Valenciana	20.7
Cantabria	63.2
Castilla la Mancha	93.0
Castilla y León	95.2
Cataluña	26.2
Extremadura	21.5
Galicia	105.1
La Rioja	59.2
Madrid	4.8
Murcia	40.9
Navarra	67.0
País Vasco	24.3

It is interesting to see that the penetration of distributed generation in terms of the demand is very high, being even greater than a 100% in Asturias and Galicia. The proposed methodology considers independent coefficients for demand and generation in the different levels, avoiding obtaining a net value of energy. Note that a case in which the energy generation and demand compensates among them in a month, the result could be a net energy of zero. The methodology is robust enough to avoid assigning zero losses when the distributed generation is closer to the demand.

The weighted average method has the deficiency that ignores the effect of the distributed generation, but the proposed method is intended to overcome this issue. It can be seen from the results that Asturias and Galicia consequently brought lower losses for the proposed method in comparison with the weighted average method because of the effect of the distributed generation.

The other main driver of losses is the low voltage demand. Level NT0 tend to have distribution lines with high resistances and high currents and most of the demand is usually connected to it, predominantly domestic loads. Andalucía, Castilla la Mancha and Madrid are the regions on the top places with higher low voltage demand, over 60%. When analyzing Table 22 and correlating it with the allocation results from the proposed method, it can be seen that the autonomous communities mentioned before present losses values below those allocated with the pro-rata method.

Table 22 Percentage of low voltage demand per region

Region	Low voltage demand (%)
Andalucía	66
Aragón	52
Asturias	49
C. Valenciana	58
Cantabria	52
Castilla la Mancha	61
Castilla y León	54
Cataluña	57
Extremadura	72
Galicia	57
La Rioja	56
Madrid	63
Murcia	50
Navarra	40
País Vasco	46

The proposed allocation method brings results with an expected behavior favoring higher losses in the low voltage levels and distributed generation. It is still interesting to see that the pro-rata method and the standard losses method allow reaching similar results with less data requirements.

5 Conclusions

The main motivation for the present study was to present a method to allocate losses among geopolitical regions, focused on the available information to the Spanish Transmission System Operator, being the main problem the absence of data about the regional interchanges at the distribution level. The research allowed reaching the following conclusions:

- Distribution losses can be allocated to regions through the use of the allocating methods to assign based on responsibility of demand and generation.
- An allocation method consisting in the use of losses coefficients for generation and demand with voltage discrimination was suggested and satisfactorily validated using a test system.
- A methodology to obtain losses coefficients is proposed and required data for its computation is possible from the information published by the Spanish Regulatory Authority.
- A step by step procedure with a real case was successfully applied and consists in 4 steps: coefficients computation, losses estimation and a matching process with real total losses.
- The method allows computing distribution losses with a reduced availability of information where the distribution system is modelled with 4 nodes simplification representing the main voltage ranges.
- The proposed methodology was compared with simpler methods based like the pro-rata and the application of standard losses and results were similar. Despite of this, the proposed method demonstrated to be sensitive to the main drivers of losses: distributed generation and low voltage demand.

As a result of the study, it was possible to identify some aspects that can be improved to the energy balance process executed by the Department of Statistics and Information of REE:

- Downstream flows from transmission to distribution are obtained from estimations. It is a priority to have internal access to this information to properly apply the proposed methodology.
- Transmission losses per region are obtained from a pro-rata computation, but they can be computed directly as a difference of the inflows and outflows of the region at the transmission level. As mentioned before, it is necessary to have access to the information regarding the transmission to distribution flows.

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7 Annex

7.1 Test system model for Matpower 5.1

7.1.1 Branches and loads data for the base case.

fbus	tbus	r	x	b	rateA	rateB	rateC	ratio	angle	status	angmin	angmax	
1	2	0.00281	0.02810	0.00712	0	0	0	0	0	1	-360	360	;
1	4	0.00304	0.03040	0.00658	0	0	0	0	0	1	-360	360	;
1	5	0.00064	0.00640	0.03126	0	0	0	0	0	1	-360	360	;
2	3	0.00108	0.01080	0.01852	0	0	0	0	0	1	-360	360	;
3	4	0.00297	0.02970	0.00674	0	0	0	0	0	1	-360	360	;
4	5	0.00297	0.02970	0.00674	0	0	0	0	0	1	-360	360	;
3	60001	0.00000	0.06667	0.00000	0	0	0	0	0	1	-360	360	;
3	60002	0.00000	0.10000	0.00000	0	0	0	0	0	1	-360	360	;
3	60003	0.00000	0.20000	0.00000	0	0	0	0	0	1	-360	360	;
4	90001	0.00000	0.05000	0.00000	0	0	0	0	0	1	-360	360	;
4	90002	0.00000	0.10000	0.00000	0	0	0	0	0	1	-360	360	;
4	90003	0.00000	0.10000	0.00000	0	0	0	0	0	1	-360	360	;
4	90004	0.00000	0.20000	0.00000	0	0	0	0	0	1	-360	360	;
4	90005	0.00000	0.10000	0.00000	0	0	0	0	0	1	-360	360	;
60001	60101	0.00032	0.00055	0.00001	0	0	0	0	0	1	-360	360	;
60001	60201	0.01282	0.02223	0.00033	0	0	0	0	0	1	-360	360	;
60001	60301	0.00139	0.00159	0.00002	0	0	0	0	0	1	-360	360	;
60001	60401	0.00033	0.00055	0.00001	0	0	0	0	0	1	-360	360	;
60001	60501	0.00033	0.00055	0.00001	0	0	0	0	0	1	-360	360	;
60001	60601	0.02163	0.03636	0.00057	0	0	0	0	0	1	-360	360	;
60001	60701	0.02163	0.03636	0.00057	0	0	0	0	0	1	-360	360	;
60001	60801	0.00024	0.00040	0.00001	0	0	0	0	0	1	-360	360	;
60001	60901	0.00024	0.00040	0.00001	0	0	0	0	0	1	-360	360	;
60001	61001	0.00033	0.00057	0.00001	0	0	0	0	0	1	-360	360	;
60001	61101	0.00179	0.00206	0.00003	0	0	0	0	0	1	-360	360	;
60002	61201	0.04114	0.04734	0.00064	0	0	0	0	0	1	-360	360	;
60002	61301	0.00026	0.00045	0.00001	0	0	0	0	0	1	-360	360	;
60002	61401	0.02613	0.04529	0.00066	0	0	0	0	0	1	-360	360	;
60002	61501	0.00051	0.00089	0.00001	0	0	0	0	0	1	-360	360	;
60002	61601	0.00019	0.00037	0.00000	0	0	0	0	0	1	-360	360	;
60003	61735	0.00799	0.01343	0.00021	0	0	0	0	0	1	-360	360	;
60003	61835	0.00799	0.01343	0.00021	0	0	0	0	0	1	-360	360	;
60101	60102	0.03481	0.03447	0.00048	0	0	0	0	0	1	-360	360	;
60102	60103	0.02767	0.02821	0.00037	0	0	0	0	0	1	-360	360	;
60103	60104	0.00490	0.00548	0.00008	0	0	0	0	0	1	-360	360	;

60104	60105	0.00490	0.00548	0.00008	0	0	0	0	0	1	-360	360 ;
60105	60106	0.04035	0.04115	0.00054	0	0	0	0	0	1	-360	360 ;
60106	60107	0.01652	0.01012	0.00012	0	0	0	0	0	1	-360	360 ;
60106	60108	0.03135	0.03197	0.00042	0	0	0	0	0	1	-360	360 ;
60108	60109	0.01831	0.01867	0.00025	0	0	0	0	0	1	-360	360 ;
60108	60125	0.02421	0.02469	0.00032	0	0	0	0	0	1	-360	360 ;
60109	60110	0.04670	0.05373	0.00073	0	0	0	0	0	1	-360	360 ;
60109	60111	0.10493	0.10699	0.00141	0	0	0	0	0	1	-360	360 ;
60111	60112	0.00284	0.00244	0.00003	0	0	0	0	0	1	-360	360 ;
60111	60113	0.03342	0.03407	0.00045	0	0	0	0	0	1	-360	360 ;
60113	60114	0.01452	0.01481	0.00019	0	0	0	0	0	1	-360	360 ;
60113	60115	0.04941	0.05038	0.00066	0	0	0	0	0	1	-360	360 ;
60115	60116	0.00338	0.00335	0.00005	0	0	0	0	0	1	-360	360 ;
60115	60117	0.00306	0.00352	0.00005	0	0	0	0	0	1	-360	360 ;
60125	60126	0.00543	0.00554	0.00007	0	0	0	0	0	1	-360	360 ;
60201	60202	0.00699	0.01175	0.00018	0	0	0	0	0	1	-360	360 ;
60202	60203	0.02610	0.04524	0.00066	0	0	0	0	0	1	-360	360 ;
60203	60204	0.01282	0.02155	0.00034	0	0	0	0	0	1	-360	360 ;
60204	60205	0.00063	0.00072	0.00001	0	0	0	0	0	1	-360	360 ;
60204	60206	0.01323	0.02293	0.00034	0	0	0	0	0	1	-360	360 ;
60206	60207	0.06961	0.08008	0.00109	0	0	0	0	0	1	-360	360 ;
60206	60209	0.01015	0.01168	0.00016	0	0	0	0	0	1	-360	360 ;
60206	60213	0.11272	0.19539	0.00286	0	0	0	0	0	1	-360	360 ;
60207	60208	0.00034	0.00038	0.00001	0	0	0	0	0	1	-360	360 ;
60209	60210	0.00452	0.00505	0.00007	0	0	0	0	0	1	-360	360 ;
60210	60211	0.00268	0.00299	0.00004	0	0	0	0	0	1	-360	360 ;
60210	60212	0.00013	0.00014	0.00000	0	0	0	0	0	1	-360	360 ;
60213	60214	0.00749	0.00862	0.00012	0	0	0	0	0	1	-360	360 ;
60214	60215	0.01940	0.02232	0.00030	0	0	0	0	0	1	-360	360 ;
60214	60218	0.01712	0.01970	0.00027	0	0	0	0	0	1	-360	360 ;
60215	60216	0.00596	0.00685	0.00009	0	0	0	0	0	1	-360	360 ;
60215	60217	0.09929	0.11422	0.00155	0	0	0	0	0	1	-360	360 ;
60218	60219	0.00078	0.00135	0.00002	0	0	0	0	0	1	-360	360 ;
60219	60221	0.00051	0.00059	0.00001	0	0	0	0	0	1	-360	360 ;
60301	60302	0.01760	0.01758	0.00023	0	0	0	0	0	1	-360	360 ;
60302	60303	0.00615	0.01034	0.00016	0	0	0	0	0	1	-360	360 ;
60303	60304	0.03300	0.03297	0.00043	0	0	0	0	0	1	-360	360 ;
60304	60305	0.00353	0.00588	0.00009	0	0	0	0	0	1	-360	360 ;
60304	60306	0.00378	0.00629	0.00010	0	0	0	0	0	1	-360	360 ;
60306	60307	0.01040	0.01802	0.00026	0	0	0	0	0	1	-360	360 ;
60306	60312	0.02624	0.04549	0.00067	0	0	0	0	0	1	-360	360 ;
60307	60308	0.00466	0.00536	0.00007	0	0	0	0	0	1	-360	360 ;
60307	60309	0.01926	0.02216	0.00030	0	0	0	0	0	1	-360	360 ;
60309	60310	0.01999	0.02233	0.00032	0	0	0	0	0	1	-360	360 ;
60312	60313	0.02760	0.04784	0.00070	0	0	0	0	0	1	-360	360 ;

60313	60314	0.00958	0.01103	0.00015	0	0	0	0	0	1	-360	360 ;
60314	60315	0.00597	0.00687	0.00009	0	0	0	0	0	1	-360	360 ;
60314	60316	0.00611	0.00623	0.00008	0	0	0	0	0	1	-360	360 ;
60316	60318	0.00269	0.00310	0.00004	0	0	0	0	0	1	-360	360 ;
60318	60319	0.00104	0.00181	0.00003	0	0	0	0	0	1	-360	360 ;
60319	60320	0.00010	0.00012	0.00000	0	0	0	0	0	1	-360	360 ;
60319	60321	0.00893	0.01548	0.00023	0	0	0	0	0	1	-360	360 ;
60321	60322	0.16298	0.18750	0.00255	0	0	0	0	0	1	-360	360 ;
60321	60325	0.03817	0.06616	0.00097	0	0	0	0	0	1	-360	360 ;
60322	60323	0.00017	0.00019	0.00000	0	0	0	0	0	1	-360	360 ;
60322	60335	0.02331	0.02682	0.00036	0	0	0	0	0	1	-360	360 ;
60324	60335	0.01233	0.01419	0.00019	0	0	0	0	0	1	-360	360 ;
60325	60326	0.00111	0.00186	0.00003	0	0	0	0	0	1	-360	360 ;
60325	60327	0.05379	0.09324	0.00136	0	0	0	0	0	1	-360	360 ;
60327	60328	0.00460	0.00459	0.00006	0	0	0	0	0	1	-360	360 ;
60327	60331	0.04613	0.04608	0.00060	0	0	0	0	0	1	-360	360 ;
60328	60329	0.00445	0.00512	0.00007	0	0	0	0	0	1	-360	360 ;
60329	60330	0.05902	0.05896	0.00077	0	0	0	0	0	1	-360	360 ;
60331	60332	0.09415	0.09406	0.00123	0	0	0	0	0	1	-360	360 ;
60332	60333	0.00019	0.00019	0.00000	0	0	0	0	0	1	-360	360 ;
60332	60334	0.02215	0.02213	0.00029	0	0	0	0	0	1	-360	360 ;
60401	60402	0.02762	0.02735	0.00038	0	0	0	0	0	1	-360	360 ;
60402	60403	0.02712	0.02685	0.00037	0	0	0	0	0	1	-360	360 ;
60402	60409	0.01302	0.01290	0.00018	0	0	0	0	0	1	-360	360 ;
60403	60404	0.02586	0.02561	0.00036	0	0	0	0	0	1	-360	360 ;
60403	60410	0.00491	0.00548	0.00008	0	0	0	0	0	1	-360	360 ;
60404	60405	0.00395	0.00391	0.00005	0	0	0	0	0	1	-360	360 ;
60404	60411	0.00032	0.00036	0.00001	0	0	0	0	0	1	-360	360 ;
60404	60412	0.00404	0.00451	0.00007	0	0	0	0	0	1	-360	360 ;
60405	60406	0.00313	0.00310	0.00004	0	0	0	0	0	1	-360	360 ;
60405	60415	0.00039	0.00043	0.00001	0	0	0	0	0	1	-360	360 ;
60406	60407	0.00727	0.00720	0.00010	0	0	0	0	0	1	-360	360 ;
60406	60417	0.00023	0.00026	0.00000	0	0	0	0	0	1	-360	360 ;
60407	60418	0.00038	0.00042	0.00001	0	0	0	0	0	1	-360	360 ;
60412	60413	0.00079	0.00088	0.00001	0	0	0	0	0	1	-360	360 ;
60412	60414	0.00289	0.00323	0.00005	0	0	0	0	0	1	-360	360 ;
60415	60416	0.00013	0.00013	0.00000	0	0	0	0	0	1	-360	360 ;
60501	60502	0.02762	0.02735	0.00038	0	0	0	0	0	1	-360	360 ;
60502	60503	0.02712	0.02685	0.00037	0	0	0	0	0	1	-360	360 ;
60503	60504	0.02586	0.02561	0.00036	0	0	0	0	0	1	-360	360 ;
60504	60505	0.00395	0.00391	0.00005	0	0	0	0	0	1	-360	360 ;
60504	60512	0.00404	0.00451	0.00007	0	0	0	0	0	1	-360	360 ;
60505	60506	0.00313	0.00310	0.00004	0	0	0	0	0	1	-360	360 ;
60505	60515	0.00039	0.00043	0.00001	0	0	0	0	0	1	-360	360 ;
60506	60507	0.00727	0.00720	0.00010	0	0	0	0	0	1	-360	360 ;

60507	60508	0.00381	0.00377	0.00005	0	0	0	0	0	1	-360	360 ;
60601	60602	0.10632	0.10841	0.00143	0	0	0	0	0	1	-360	360 ;
60601	60607	0.00194	0.00326	0.00005	0	0	0	0	0	1	-360	360 ;
60602	60603	0.02345	0.02698	0.00037	0	0	0	0	0	1	-360	360 ;
60603	60604	0.00072	0.00073	0.00001	0	0	0	0	0	1	-360	360 ;
60604	60605	0.00093	0.00108	0.00001	0	0	0	0	0	1	-360	360 ;
60604	60606	0.01950	0.01988	0.00026	0	0	0	0	0	1	-360	360 ;
60607	60609	0.01167	0.01962	0.00031	0	0	0	0	0	1	-360	360 ;
60609	60610	0.01001	0.01118	0.00016	0	0	0	0	0	1	-360	360 ;
60609	60645	0.01549	0.02604	0.00041	0	0	0	0	0	1	-360	360 ;
60701	60707	0.00194	0.00326	0.00005	0	0	0	0	0	1	-360	360 ;
60707	60708	0.00030	0.00053	0.00001	0	0	0	0	0	1	-360	360 ;
60707	60709	0.01167	0.01962	0.00031	0	0	0	0	0	1	-360	360 ;
60709	60745	0.01549	0.02604	0.00041	0	0	0	0	0	1	-360	360 ;
60711	60712	0.00890	0.00882	0.00012	0	0	0	0	0	1	-360	360 ;
60711	60745	0.01401	0.02429	0.00036	0	0	0	0	0	1	-360	360 ;
60801	60802	0.00752	0.00745	0.00010	0	0	0	0	0	1	-360	360 ;
60802	60803	0.01101	0.01091	0.00015	0	0	0	0	0	1	-360	360 ;
60802	60815	0.01635	0.01619	0.00023	0	0	0	0	0	1	-360	360 ;
60803	60804	0.00119	0.00133	0.00002	0	0	0	0	0	1	-360	360 ;
60804	60805	0.00089	0.00099	0.00001	0	0	0	0	0	1	-360	360 ;
60805	60806	0.00162	0.00181	0.00003	0	0	0	0	0	1	-360	360 ;
60806	60807	0.00363	0.00405	0.00006	0	0	0	0	0	1	-360	360 ;
60807	60808	0.00745	0.00456	0.00005	0	0	0	0	0	1	-360	360 ;
60808	60809	0.00236	0.00145	0.00002	0	0	0	0	0	1	-360	360 ;
60808	60811	0.00060	0.00037	0.00000	0	0	0	0	0	1	-360	360 ;
60809	60810	0.00046	0.00053	0.00001	0	0	0	0	0	1	-360	360 ;
60815	60817	0.01230	0.01218	0.00017	0	0	0	0	0	1	-360	360 ;
60817	60818	0.00255	0.00285	0.00004	0	0	0	0	0	1	-360	360 ;
60818	60819	0.00243	0.00240	0.00003	0	0	0	0	0	1	-360	360 ;
60819	60821	0.01539	0.01525	0.00021	0	0	0	0	0	1	-360	360 ;
60821	60822	0.00995	0.00985	0.00014	0	0	0	0	0	1	-360	360 ;
60822	60823	0.00238	0.00265	0.00004	0	0	0	0	0	1	-360	360 ;
60823	60825	0.00261	0.00292	0.00004	0	0	0	0	0	1	-360	360 ;
60825	60827	0.00075	0.00084	0.00001	0	0	0	0	0	1	-360	360 ;
60827	60828	0.00067	0.00074	0.00001	0	0	0	0	0	1	-360	360 ;
60901	60902	0.00752	0.00745	0.00010	0	0	0	0	0	1	-360	360 ;
60902	60903	0.01101	0.01091	0.00015	0	0	0	0	0	1	-360	360 ;
60902	60915	0.01635	0.01619	0.00023	0	0	0	0	0	1	-360	360 ;
60903	60904	0.00119	0.00133	0.00002	0	0	0	0	0	1	-360	360 ;
60904	60905	0.00089	0.00099	0.00001	0	0	0	0	0	1	-360	360 ;
60904	60914	0.00022	0.00022	0.00000	0	0	0	0	0	1	-360	360 ;
60905	60906	0.00162	0.00181	0.00003	0	0	0	0	0	1	-360	360 ;
60906	60912	0.00014	0.00016	0.00000	0	0	0	0	0	1	-360	360 ;
60915	60916	0.00086	0.00096	0.00001	0	0	0	0	0	1	-360	360 ;

60915	60917	0.01230	0.01218	0.00017	0	0	0	0	0	1	-360	360 ;
60917	60918	0.00255	0.00285	0.00004	0	0	0	0	0	1	-360	360 ;
60918	60919	0.00243	0.00240	0.00003	0	0	0	0	0	1	-360	360 ;
60919	60920	0.00016	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
60919	60921	0.01539	0.01525	0.00021	0	0	0	0	0	1	-360	360 ;
60921	60922	0.00995	0.00985	0.00014	0	0	0	0	0	1	-360	360 ;
60922	60923	0.00238	0.00265	0.00004	0	0	0	0	0	1	-360	360 ;
60923	60924	0.00091	0.00090	0.00001	0	0	0	0	0	1	-360	360 ;
60923	60925	0.00261	0.00292	0.00004	0	0	0	0	0	1	-360	360 ;
60925	60926	0.00065	0.00065	0.00001	0	0	0	0	0	1	-360	360 ;
60925	60927	0.00075	0.00084	0.00001	0	0	0	0	0	1	-360	360 ;
60927	60929	0.00466	0.00521	0.00008	0	0	0	0	0	1	-360	360 ;
61001	61002	0.11152	0.11370	0.00149	0	0	0	0	0	1	-360	360 ;
61002	61004	0.01099	0.01265	0.00017	0	0	0	0	0	1	-360	360 ;
61004	61005	0.00572	0.00658	0.00009	0	0	0	0	0	1	-360	360 ;
61004	61007	0.03453	0.03520	0.00046	0	0	0	0	0	1	-360	360 ;
61005	61006	0.00067	0.00077	0.00001	0	0	0	0	0	1	-360	360 ;
61007	61008	0.00186	0.00186	0.00002	0	0	0	0	0	1	-360	360 ;
61008	61009	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
61009	61010	0.01360	0.01358	0.00018	0	0	0	0	0	1	-360	360 ;
61010	61011	0.00055	0.00062	0.00001	0	0	0	0	0	1	-360	360 ;
61010	61012	0.00048	0.00053	0.00001	0	0	0	0	0	1	-360	360 ;
61012	61013	0.00048	0.00053	0.00001	0	0	0	0	0	1	-360	360 ;
61013	61025	0.00432	0.00497	0.00007	0	0	0	0	0	1	-360	360 ;
61014	61015	0.02974	0.03033	0.00040	0	0	0	0	0	1	-360	360 ;
61014	61025	0.01053	0.01052	0.00014	0	0	0	0	0	1	-360	360 ;
61015	61016	0.00693	0.00595	0.00008	0	0	0	0	0	1	-360	360 ;
61015	61017	0.00799	0.00815	0.00011	0	0	0	0	0	1	-360	360 ;
61017	61018	0.00160	0.00137	0.00002	0	0	0	0	0	1	-360	360 ;
61017	61019	0.02560	0.02610	0.00034	0	0	0	0	0	1	-360	360 ;
61019	61020	0.01913	0.01641	0.00021	0	0	0	0	0	1	-360	360 ;
61101	61102	0.02999	0.02996	0.00039	0	0	0	0	0	1	-360	360 ;
61102	61103	0.00186	0.00186	0.00002	0	0	0	0	0	1	-360	360 ;
61102	61104	0.00214	0.00214	0.00003	0	0	0	0	0	1	-360	360 ;
61104	61105	0.00172	0.00172	0.00002	0	0	0	0	0	1	-360	360 ;
61104	61106	0.03104	0.03101	0.00041	0	0	0	0	0	1	-360	360 ;
61106	61107	0.00117	0.00135	0.00002	0	0	0	0	0	1	-360	360 ;
61106	61108	0.03425	0.03422	0.00045	0	0	0	0	0	1	-360	360 ;
61108	61109	0.00451	0.00519	0.00007	0	0	0	0	0	1	-360	360 ;
61108	61112	0.00428	0.00428	0.00006	0	0	0	0	0	1	-360	360 ;
61109	61110	0.00023	0.00026	0.00000	0	0	0	0	0	1	-360	360 ;
61109	61111	0.00257	0.00249	0.00003	0	0	0	0	0	1	-360	360 ;
61112	61113	0.00297	0.00342	0.00005	0	0	0	0	0	1	-360	360 ;
61113	61114	0.00104	0.00119	0.00002	0	0	0	0	0	1	-360	360 ;
61113	61115	0.13560	0.13548	0.00177	0	0	0	0	0	1	-360	360 ;

61201	61210	0.10363	0.11923	0.00162	0	0	0	0	0	1	-360	360 ;
61202	61210	0.00032	0.00036	0.00000	0	0	0	0	0	1	-360	360 ;
61202	61211	0.00032	0.00036	0.00000	0	0	0	0	0	1	-360	360 ;
61203	61204	0.00182	0.00210	0.00003	0	0	0	0	0	1	-360	360 ;
61203	61205	0.00808	0.00929	0.00013	0	0	0	0	0	1	-360	360 ;
61203	61211	0.01322	0.01521	0.00021	0	0	0	0	0	1	-360	360 ;
61205	61208	0.08263	0.08425	0.00111	0	0	0	0	0	1	-360	360 ;
61208	61209	0.00136	0.00139	0.00002	0	0	0	0	0	1	-360	360 ;
61301	61302	0.03399	0.03911	0.00053	0	0	0	0	0	1	-360	360 ;
61302	61303	0.00055	0.00055	0.00001	0	0	0	0	0	1	-360	360 ;
61303	61304	0.00013	0.00014	0.00000	0	0	0	0	0	1	-360	360 ;
61303	61305	0.00055	0.00055	0.00001	0	0	0	0	0	1	-360	360 ;
61305	61306	0.01806	0.01841	0.00024	0	0	0	0	0	1	-360	360 ;
61306	61307	0.01325	0.01524	0.00021	0	0	0	0	0	1	-360	360 ;
61306	61309	0.05249	0.05352	0.00070	0	0	0	0	0	1	-360	360 ;
61307	61308	0.01220	0.01363	0.00020	0	0	0	0	0	1	-360	360 ;
61309	61310	0.00115	0.00132	0.00002	0	0	0	0	0	1	-360	360 ;
61309	61311	0.20252	0.20649	0.00271	0	0	0	0	0	1	-360	360 ;
61311	61312	0.01270	0.01462	0.00020	0	0	0	0	0	1	-360	360 ;
61311	61313	0.05968	0.06085	0.00080	0	0	0	0	0	1	-360	360 ;
61313	61314	0.00317	0.00194	0.00002	0	0	0	0	0	1	-360	360 ;
61313	61315	0.00473	0.00482	0.00006	0	0	0	0	0	1	-360	360 ;
61401	61405	0.00114	0.00116	0.00002	0	0	0	0	0	1	-360	360 ;
61401	61412	0.02150	0.02192	0.00029	0	0	0	0	0	1	-360	360 ;
61402	61403	0.01764	0.01799	0.00024	0	0	0	0	0	1	-360	360 ;
61402	61413	0.00055	0.00055	0.00001	0	0	0	0	0	1	-360	360 ;
61403	61404	0.00559	0.00570	0.00007	0	0	0	0	0	1	-360	360 ;
61405	61406	0.00109	0.00111	0.00001	0	0	0	0	0	1	-360	360 ;
61405	61407	0.01246	0.01270	0.00017	0	0	0	0	0	1	-360	360 ;
61407	61408	0.08208	0.08369	0.00110	0	0	0	0	0	1	-360	360 ;
61408	61409	0.00035	0.00026	0.00000	0	0	0	0	0	1	-360	360 ;
61408	61410	0.00132	0.00152	0.00002	0	0	0	0	0	1	-360	360 ;
61410	61411	0.00068	0.00070	0.00001	0	0	0	0	0	1	-360	360 ;
61412	61413	0.00055	0.00055	0.00001	0	0	0	0	0	1	-360	360 ;
61501	61502	0.00273	0.00278	0.00004	0	0	0	0	0	1	-360	360 ;
61502	61503	0.13448	0.07043	0.00083	0	0	0	0	0	1	-360	360 ;
61503	61504	0.00058	0.00065	0.00001	0	0	0	0	0	1	-360	360 ;
61504	61505	0.00091	0.00093	0.00001	0	0	0	0	0	1	-360	360 ;
61504	61506	0.00112	0.00126	0.00002	0	0	0	0	0	1	-360	360 ;
61601	61602	0.07209	0.08293	0.00113	0	0	0	0	0	1	-360	360 ;
61602	61603	0.00170	0.00190	0.00003	0	0	0	0	0	1	-360	360 ;
61708	61714	0.00130	0.00129	0.00002	0	0	0	0	0	1	-360	360 ;
61711	61713	0.01059	0.01049	0.00015	0	0	0	0	0	1	-360	360 ;
61711	61715	0.02493	0.04322	0.00063	0	0	0	0	0	1	-360	360 ;
61713	61714	0.00354	0.00350	0.00005	0	0	0	0	0	1	-360	360 ;

61715	61716	0.00037	0.00064	0.00001	0	0	0	0	0	1	-360	360 ;
61716	61718	0.00303	0.00525	0.00008	0	0	0	0	0	1	-360	360 ;
61718	61719	0.02094	0.03629	0.00053	0	0	0	0	0	1	-360	360 ;
61719	61720	0.00390	0.00677	0.00010	0	0	0	0	0	1	-360	360 ;
61720	61722	0.00030	0.00051	0.00001	0	0	0	0	0	1	-360	360 ;
61722	61726	0.00102	0.00171	0.00003	0	0	0	0	0	1	-360	360 ;
61726	61728	0.00257	0.00432	0.00007	0	0	0	0	0	1	-360	360 ;
61728	61730	0.00170	0.00286	0.00004	0	0	0	0	0	1	-360	360 ;
61730	61732	0.00170	0.00286	0.00004	0	0	0	0	0	1	-360	360 ;
61732	61733	0.00167	0.00280	0.00004	0	0	0	0	0	1	-360	360 ;
61732	61735	0.00030	0.00051	0.00001	0	0	0	0	0	1	-360	360 ;
61732	61737	0.00699	0.01175	0.00018	0	0	0	0	0	1	-360	360 ;
61737	61739	0.00722	0.01214	0.00019	0	0	0	0	0	1	-360	360 ;
61739	61740	0.00008	0.00009	0.00000	0	0	0	0	0	0	-360	360 ;
61819	61820	0.00390	0.00677	0.00010	0	0	0	0	0	1	-360	360 ;
61820	61821	0.00010	0.00011	0.00000	0	0	0	0	0	1	-360	360 ;
61820	61822	0.00030	0.00051	0.00001	0	0	0	0	0	1	-360	360 ;
61822	61823	0.00028	0.00028	0.00000	0	0	0	0	0	1	-360	360 ;
61822	61826	0.00102	0.00171	0.00003	0	0	0	0	0	1	-360	360 ;
61823	61824	0.00018	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
61823	61825	0.00064	0.00063	0.00001	0	0	0	0	0	1	-360	360 ;
61826	61827	0.00018	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
61826	61828	0.00257	0.00432	0.00007	0	0	0	0	0	1	-360	360 ;
61828	61829	0.00029	0.00029	0.00000	0	0	0	0	0	1	-360	360 ;
61828	61830	0.00170	0.00286	0.00004	0	0	0	0	0	1	-360	360 ;
61830	61831	0.00010	0.00011	0.00000	0	0	0	0	0	1	-360	360 ;
61830	61832	0.00170	0.00286	0.00004	0	0	0	0	0	1	-360	360 ;
61832	61833	0.00167	0.00280	0.00004	0	0	0	0	0	1	-360	360 ;
61832	61835	0.00030	0.00051	0.00001	0	0	0	0	0	1	-360	360 ;
61832	61837	0.00699	0.01175	0.00018	0	0	0	0	0	1	-360	360 ;
61833	61834	0.00060	0.00059	0.00001	0	0	0	0	0	1	-360	360 ;
61835	61836	0.00009	0.00009	0.00000	0	0	0	0	0	1	-360	360 ;
61837	61838	0.00048	0.00053	0.00001	0	0	0	0	0	1	-360	360 ;
61837	61839	0.00722	0.01214	0.00019	0	0	0	0	0	1	-360	360 ;
61839	61840	0.00008	0.00009	0.00000	0	0	0	0	0	1	-360	360 ;
90001	90101	0.01174	0.02067	0.00029	0	0	0	0	0	1	-360	360 ;
90001	90201	0.01174	0.02067	0.00029	0	0	0	0	0	1	-360	360 ;
90001	90301	0.00830	0.01460	0.00021	0	0	0	0	0	1	-360	360 ;
90001	90401	0.00232	0.00403	0.00006	0	0	0	0	0	1	-360	360 ;
90001	90538	0.02731	0.07618	0.00116	0	0	0	0	0	1	-360	360 ;
90001	90601	0.01242	0.01429	0.00019	0	0	0	0	0	1	-360	360 ;
90001	90701	0.00830	0.01461	0.00021	0	0	0	0	0	1	-360	360 ;
90001	90801	0.00591	0.01650	0.00025	0	0	0	0	0	1	-360	360 ;
90001	90802	0.00712	0.01985	0.00030	0	0	0	0	0	0	-360	360 ;
90001	90902	0.00712	0.01985	0.00030	0	0	0	0	0	1	-360	360 ;

90001	91001	0.00777	0.01369	0.00019	0	0	0	0	0	1	-360	360 ;
90001	91138	0.02731	0.07618	0.00116	0	0	0	0	0	1	-360	360 ;
90002	91201	0.05215	0.09039	0.00132	0	0	0	0	0	1	-360	360 ;
90002	91301	0.06848	0.08127	0.00137	0	0	0	0	0	1	-360	360 ;
90002	91401	0.01392	0.01625	0.00021	0	0	0	0	0	1	-360	360 ;
90002	91501	0.01902	0.02222	0.00029	0	0	0	0	0	1	-360	360 ;
90002	91601	0.03909	0.04564	0.00060	0	0	0	0	0	1	-360	360 ;
90002	91701	0.01680	0.01385	0.00017	0	0	0	0	0	1	-360	360 ;
90002	91813	0.00128	0.00357	0.00005	0	0	0	0	0	1	-360	360 ;
90002	91909	0.01621	0.01652	0.00022	0	0	0	0	0	1	-360	360 ;
90003	92001	0.02367	0.02764	0.00036	0	0	0	0	0	1	-360	360 ;
90003	92101	0.13116	0.22735	0.00332	0	0	0	0	0	1	-360	360 ;
90003	92201	0.12496	0.14375	0.00195	0	0	0	0	0	1	-360	360 ;
90003	92301	0.00469	0.00539	0.00007	0	0	0	0	0	1	-360	360 ;
90003	92401	0.00280	0.00327	0.00004	0	0	0	0	0	1	-360	360 ;
90003	92501	0.00440	0.00514	0.00007	0	0	0	0	0	1	-360	360 ;
90003	92601	0.00329	0.00570	0.00008	0	0	0	0	0	1	-360	360 ;
90003	92701	0.02428	0.02835	0.00037	0	0	0	0	0	1	-360	360 ;
90003	92807	0.02843	0.02897	0.00038	0	0	0	0	0	1	-360	360 ;
90003	92901	0.01223	0.04593	0.00000	0	0	0	0	0	1	-360	360 ;
90004	93001	0.07110	0.08180	0.00111	0	0	0	0	0	1	-360	360 ;
90004	93101	0.02169	0.02496	0.00034	0	0	0	0	0	1	-360	360 ;
90004	93201	0.01164	0.01339	0.00018	0	0	0	0	0	1	-360	360 ;
90004	93306	0.01840	0.02117	0.00029	0	0	0	0	0	1	-360	360 ;
90005	93401	0.00392	0.00400	0.00005	0	0	0	0	0	1	-360	360 ;
90005	93501	0.00285	0.00328	0.00004	0	0	0	0	0	1	-360	360 ;
90005	93601	0.05434	0.06252	0.00085	0	0	0	0	0	1	-360	360 ;
90005	93701	0.00774	0.02158	0.00033	0	0	0	0	0	1	-360	360 ;
90005	93801	0.01629	0.01902	0.00025	0	0	0	0	0	1	-360	360 ;
90005	93901	0.01629	0.01902	0.00025	0	0	0	0	0	1	-360	360 ;
90005	94001	0.00988	0.01136	0.00015	0	0	0	0	0	1	-360	360 ;
90101	90103	0.00235	0.00413	0.00006	0	0	0	0	0	1	-360	360 ;
90201	90202	0.00814	0.00951	0.00013	0	0	0	0	0	1	-360	360 ;
90201	90203	0.00235	0.00413	0.00006	0	0	0	0	0	1	-360	360 ;
90301	90302	0.02155	0.01981	0.00032	0	0	0	0	0	1	-360	360 ;
90302	90303	0.02824	0.02924	0.00049	0	0	0	0	0	1	-360	360 ;
90401	90402	0.00335	0.00580	0.00008	0	0	0	0	0	1	-360	360 ;
90401	90413	0.03469	0.03592	0.00060	0	0	0	0	0	1	-360	360 ;
90402	90403	0.03796	0.06580	0.00096	0	0	0	0	0	1	-360	360 ;
90402	90412	0.00070	0.00073	0.00001	0	0	0	0	0	1	-360	360 ;
90403	90404	0.00337	0.00387	0.00005	0	0	0	0	0	1	-360	360 ;
90403	90408	0.01021	0.01770	0.00026	0	0	0	0	0	1	-360	360 ;
90404	90405	0.01517	0.01746	0.00024	0	0	0	0	0	1	-360	360 ;
90405	90406	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
90405	90407	0.11121	0.12795	0.00174	0	0	0	0	0	1	-360	360 ;

90408	90410	0.00019	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
90408	90411	0.00084	0.00077	0.00001	0	0	0	0	0	1	-360	360 ;
90506	90507	0.00303	0.00533	0.00008	0	0	0	0	0	1	-360	360 ;
90506	90521	0.00347	0.00405	0.00005	0	0	0	0	0	1	-360	360 ;
90506	90538	0.00321	0.00566	0.00008	0	0	0	0	0	1	-360	360 ;
90507	90508	0.00227	0.00400	0.00006	0	0	0	0	0	1	-360	360 ;
90507	90522	0.00758	0.00885	0.00012	0	0	0	0	0	1	-360	360 ;
90508	90509	0.00044	0.00078	0.00001	0	0	0	0	0	1	-360	360 ;
90508	90523	0.00134	0.00156	0.00002	0	0	0	0	0	1	-360	360 ;
90509	90510	0.00082	0.00145	0.00002	0	0	0	0	0	1	-360	360 ;
90509	90532	0.00592	0.00692	0.00009	0	0	0	0	0	1	-360	360 ;
90510	90511	0.00919	0.01618	0.00023	0	0	0	0	0	1	-360	360 ;
90510	90533	0.00079	0.00092	0.00001	0	0	0	0	0	1	-360	360 ;
90511	90534	0.00230	0.00269	0.00004	0	0	0	0	0	1	-360	360 ;
90523	90524	0.15614	0.17963	0.00244	0	0	0	0	0	1	-360	360 ;
90523	90527	0.11391	0.11608	0.00152	0	0	0	0	0	1	-360	360 ;
90524	90525	0.01673	0.01924	0.00026	0	0	0	0	0	1	-360	360 ;
90524	90526	0.00152	0.00157	0.00003	0	0	0	0	0	1	-360	360 ;
90527	90528	0.00132	0.00134	0.00002	0	0	0	0	0	1	-360	360 ;
90527	90529	0.00274	0.00315	0.00004	0	0	0	0	0	1	-360	360 ;
90529	90530	0.16798	0.19325	0.00263	0	0	0	0	0	1	-360	360 ;
90601	90602	0.00079	0.00082	0.00001	0	0	0	0	0	1	-360	360 ;
90601	90603	0.00120	0.00122	0.00002	0	0	0	0	0	1	-360	360 ;
90603	90604	0.04340	0.04993	0.00068	0	0	0	0	0	1	-360	360 ;
90603	90605	0.03858	0.03932	0.00052	0	0	0	0	0	1	-360	360 ;
90605	90607	0.03172	0.03233	0.00042	0	0	0	0	0	1	-360	360 ;
90607	90608	0.00299	0.00350	0.00005	0	0	0	0	0	1	-360	360 ;
90701	90702	0.00330	0.00580	0.00008	0	0	0	0	0	1	-360	360 ;
90701	90705	0.00177	0.00183	0.00002	0	0	0	0	0	1	-360	360 ;
90702	90703	0.01110	0.01954	0.00028	0	0	0	0	0	1	-360	360 ;
90702	90708	0.00287	0.00335	0.00004	0	0	0	0	0	1	-360	360 ;
90703	90704	0.01303	0.02293	0.00032	0	0	0	0	0	1	-360	360 ;
90703	90706	0.01140	0.01331	0.00018	0	0	0	0	0	1	-360	360 ;
90704	90707	0.01589	0.01644	0.00021	0	0	0	0	0	1	-360	360 ;
90802	90803	0.00021	0.00024	0.00000	0	0	0	0	0	0	-360	360 ;
90802	90804	0.00036	0.00043	0.00001	0	0	0	0	0	0	-360	360 ;
90804	90805	0.00016	0.00018	0.00000	0	0	0	0	0	0	-360	360 ;
90804	90806	0.00240	0.00276	0.00004	0	0	0	0	0	0	-360	360 ;
90805	90810	0.00379	0.00436	0.00006	0	0	0	0	0	0	-360	360 ;
90806	90807	0.00348	0.00401	0.00005	0	0	0	0	0	0	-360	360 ;
90902	90903	0.00016	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
90902	90904	0.00036	0.00042	0.00001	0	0	0	0	0	1	-360	360 ;
90904	90905	0.00016	0.00018	0.00000	0	0	0	0	0	1	-360	360 ;
90904	90906	0.00240	0.00276	0.00004	0	0	0	0	0	1	-360	360 ;
90905	90910	0.00379	0.00436	0.00006	0	0	0	0	0	1	-360	360 ;

90906	90907	0.00348	0.00401	0.00005	0	0	0	0	0	1	-360	360 ;
91001	91002	0.00946	0.01665	0.00024	0	0	0	0	0	1	-360	360 ;
91001	91014	0.00067	0.00079	0.00001	0	0	0	0	0	1	-360	360 ;
91001	91015	0.00038	0.00044	0.00001	0	0	0	0	0	1	-360	360 ;
91002	91016	0.00160	0.00187	0.00002	0	0	0	0	0	1	-360	360 ;
91002	91017	0.00386	0.00399	0.00005	0	0	0	0	0	1	-360	360 ;
91103	91104	0.00186	0.00328	0.00005	0	0	0	0	0	1	-360	360 ;
91103	91118	0.00596	0.00616	0.00008	0	0	0	0	0	1	-360	360 ;
91104	91105	0.01340	0.02358	0.00033	0	0	0	0	0	1	-360	360 ;
91104	91119	0.00626	0.00732	0.00010	0	0	0	0	0	1	-360	360 ;
91105	91120	0.00057	0.00067	0.00001	0	0	0	0	0	1	-360	360 ;
91105	91138	0.00114	0.00200	0.00003	0	0	0	0	0	1	-360	360 ;
91201	91202	0.01285	0.01369	0.00016	0	0	0	0	0	1	-360	360 ;
91202	91203	0.01329	0.01416	0.00017	0	0	0	0	0	1	-360	360 ;
91202	91208	0.00251	0.00289	0.00004	0	0	0	0	0	1	-360	360 ;
91203	91204	0.07117	0.07582	0.00089	0	0	0	0	0	1	-360	360 ;
91203	91209	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
91204	91205	0.06453	0.06875	0.00081	0	0	0	0	0	1	-360	360 ;
91204	91210	0.00079	0.00082	0.00001	0	0	0	0	0	1	-360	360 ;
91205	91206	0.02094	0.02409	0.00033	0	0	0	0	0	1	-360	360 ;
91206	91207	0.00102	0.00118	0.00002	0	0	0	0	0	1	-360	360 ;
91206	91211	0.00554	0.00638	0.00009	0	0	0	0	0	1	-360	360 ;
91301	91302	0.01495	0.01548	0.00026	0	0	0	0	0	1	-360	360 ;
91301	91313	0.00102	0.00106	0.00002	0	0	0	0	0	1	-360	360 ;
91302	91303	0.00916	0.01087	0.00018	0	0	0	0	0	1	-360	360 ;
91303	91304	0.01069	0.01269	0.00021	0	0	0	0	0	1	-360	360 ;
91304	91311	0.00079	0.00082	0.00001	0	0	0	0	0	1	-360	360 ;
91401	91402	0.03605	0.04148	0.00056	0	0	0	0	0	1	-360	360 ;
91402	91403	0.03604	0.04147	0.00056	0	0	0	0	0	1	-360	360 ;
91402	91408	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
91403	91404	0.00204	0.00235	0.00003	0	0	0	0	0	1	-360	360 ;
91403	91409	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
91404	91410	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
91501	91502	0.01045	0.01202	0.00016	0	0	0	0	0	1	-360	360 ;
91501	91508	0.00349	0.00402	0.00005	0	0	0	0	0	1	-360	360 ;
91502	91503	0.00977	0.01141	0.00015	0	0	0	0	0	1	-360	360 ;
91502	91509	0.00786	0.00905	0.00012	0	0	0	0	0	1	-360	360 ;
91503	91504	0.02079	0.03986	0.00052	0	0	0	0	0	1	-360	360 ;
91504	91510	0.01409	0.01621	0.00022	0	0	0	0	0	1	-360	360 ;
91601	91602	0.04847	0.05576	0.00076	0	0	0	0	0	1	-360	360 ;
91602	91603	0.00311	0.00358	0.00005	0	0	0	0	0	1	-360	360 ;
91603	91604	0.11416	0.13134	0.00179	0	0	0	0	0	1	-360	360 ;
91604	91605	0.00420	0.00483	0.00007	0	0	0	0	0	1	-360	360 ;
91604	91614	0.00634	0.00729	0.00010	0	0	0	0	0	1	-360	360 ;
91605	91606	0.04587	0.04675	0.00061	0	0	0	0	0	1	-360	360 ;

91605	91615	0.00314	0.00362	0.00005	0	0	0	0	0	1	-360	360 ;
91606	91607	0.05601	0.06444	0.00088	0	0	0	0	0	1	-360	360 ;
91607	91609	0.04217	0.04367	0.00074	0	0	0	0	0	1	-360	360 ;
91609	91610	0.01525	0.01580	0.00027	0	0	0	0	0	1	-360	360 ;
91609	91612	0.01476	0.01698	0.00023	0	0	0	0	0	1	-360	360 ;
91610	91611	0.03653	0.03782	0.00064	0	0	0	0	0	1	-360	360 ;
91611	91613	0.04356	0.05011	0.00068	0	0	0	0	0	1	-360	360 ;
91701	91702	0.02500	0.02145	0.00027	0	0	0	0	0	1	-360	360 ;
91702	91704	0.00072	0.00084	0.00001	0	0	0	0	0	1	-360	360 ;
91702	91705	0.00292	0.00336	0.00005	0	0	0	0	0	1	-360	360 ;
91705	91706	0.02750	0.02268	0.00028	0	0	0	0	0	1	-360	360 ;
91812	91835	0.02078	0.02427	0.00032	0	0	0	0	0	1	-360	360 ;
91812	91837	0.00933	0.01642	0.00023	0	0	0	0	0	1	-360	360 ;
91813	91836	0.00089	0.00105	0.00001	0	0	0	0	0	1	-360	360 ;
91813	91837	0.01373	0.03829	0.00058	0	0	0	0	0	1	-360	360 ;
91908	91909	0.00299	0.00350	0.00005	0	0	0	0	0	1	-360	360 ;
92001	92002	0.13311	0.15314	0.00208	0	0	0	0	0	1	-360	360 ;
92002	92003	0.02102	0.02418	0.00033	0	0	0	0	0	1	-360	360 ;
92003	92004	0.08257	0.09499	0.00129	0	0	0	0	0	1	-360	360 ;
92004	92005	0.04369	0.04452	0.00058	0	0	0	0	0	1	-360	360 ;
92005	92006	0.03566	0.03634	0.00048	0	0	0	0	0	1	-360	360 ;
92006	92007	0.02015	0.02054	0.00027	0	0	0	0	0	1	-360	360 ;
92006	92009	0.00916	0.01053	0.00014	0	0	0	0	0	1	-360	360 ;
92007	92008	0.00553	0.00636	0.00009	0	0	0	0	0	1	-360	360 ;
92009	92010	0.00650	0.00662	0.00009	0	0	0	0	0	1	-360	360 ;
92009	92011	0.00716	0.00730	0.00010	0	0	0	0	0	1	-360	360 ;
92201	92202	0.02580	0.02969	0.00040	0	0	0	0	0	1	-360	360 ;
92201	92206	0.05517	0.06347	0.00086	0	0	0	0	0	1	-360	360 ;
92202	92203	0.00866	0.00997	0.00014	0	0	0	0	0	1	-360	360 ;
92202	92209	0.03768	0.04335	0.00059	0	0	0	0	0	1	-360	360 ;
92203	92204	0.02324	0.02673	0.00036	0	0	0	0	0	1	-360	360 ;
92203	92207	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
92204	92205	0.09105	0.10475	0.00142	0	0	0	0	0	1	-360	360 ;
92205	92208	0.00871	0.01002	0.00014	0	0	0	0	0	1	-360	360 ;
92209	92210	0.00182	0.00213	0.00003	0	0	0	0	0	1	-360	360 ;
92209	92213	0.00227	0.00265	0.00003	0	0	0	0	0	1	-360	360 ;
92211	92212	0.00200	0.00234	0.00003	0	0	0	0	0	1	-360	360 ;
92212	92213	0.00401	0.00468	0.00006	0	0	0	0	0	1	-360	360 ;
92213	92214	0.00135	0.00157	0.00002	0	0	0	0	0	1	-360	360 ;
92214	92215	0.03611	0.04154	0.00056	0	0	0	0	0	1	-360	360 ;
92301	92302	0.00176	0.00205	0.00003	0	0	0	0	0	1	-360	360 ;
92401	92402	0.00304	0.00350	0.00005	0	0	0	0	0	1	-360	360 ;
92402	92403	0.00261	0.00300	0.00004	0	0	0	0	0	1	-360	360 ;
92403	92404	0.02089	0.02226	0.00026	0	0	0	0	0	1	-360	360 ;
92404	92405	0.14613	0.15569	0.00183	0	0	0	0	0	1	-360	360 ;

92404	92410	0.00051	0.00084	0.00001	0	0	0	0	0	1	-360	360 ;
92405	92406	0.03672	0.03581	0.00051	0	0	0	0	0	1	-360	360 ;
92406	92407	0.05610	0.05472	0.00078	0	0	0	0	0	1	-360	360 ;
92406	92411	0.03960	0.04556	0.00062	0	0	0	0	0	1	-360	360 ;
92407	92412	0.00561	0.00645	0.00009	0	0	0	0	0	1	-360	360 ;
92501	92502	0.00386	0.00444	0.00006	0	0	0	0	0	1	-360	360 ;
92502	92503	0.16446	0.16040	0.00230	0	0	0	0	0	1	-360	360 ;
92502	92513	0.00065	0.00076	0.00001	0	0	0	0	0	1	-360	360 ;
92503	92504	0.05773	0.05883	0.00077	0	0	0	0	0	1	-360	360 ;
92504	92505	0.02933	0.02989	0.00039	0	0	0	0	0	1	-360	360 ;
92504	92512	0.00647	0.01070	0.00017	0	0	0	0	0	1	-360	360 ;
92505	92506	0.07211	0.07349	0.00096	0	0	0	0	0	1	-360	360 ;
92505	92511	0.01816	0.02089	0.00028	0	0	0	0	0	1	-360	360 ;
92506	92507	0.00022	0.00022	0.00000	0	0	0	0	0	1	-360	360 ;
92506	92510	0.02212	0.02545	0.00035	0	0	0	0	0	1	-360	360 ;
92601	92602	0.01358	0.02392	0.00034	0	0	0	0	0	1	-360	360 ;
92805	92806	0.02407	0.04616	0.00061	0	0	0	0	0	1	-360	360 ;
92805	92811	0.00056	0.00065	0.00001	0	0	0	0	0	1	-360	360 ;
92806	92807	0.08021	0.13236	0.00189	0	0	0	0	0	1	-360	360 ;
92806	92812	0.00230	0.00265	0.00004	0	0	0	0	0	1	-360	360 ;
92901	92902	0.00608	0.02284	0.00000	0	0	0	0	0	1	-360	360 ;
92901	92905	0.01354	0.02348	0.00034	0	0	0	0	0	1	-360	360 ;
92902	92903	0.00478	0.01797	0.00000	0	0	0	0	0	1	-360	360 ;
92902	92906	0.00848	0.01470	0.00021	0	0	0	0	0	1	-360	360 ;
92903	92904	0.00220	0.00381	0.00006	0	0	0	0	0	1	-360	360 ;
93305	93306	0.02841	0.03268	0.00044	0	0	0	0	0	1	-360	360 ;
93305	93307	0.01237	0.01423	0.00019	0	0	0	0	0	1	-360	360 ;
93306	93310	0.00079	0.00082	0.00001	0	0	0	0	0	1	-360	360 ;
93307	93308	0.00309	0.00355	0.00005	0	0	0	0	0	1	-360	360 ;
93308	93309	0.18023	0.20735	0.00282	0	0	0	0	0	1	-360	360 ;
93401	93402	0.01452	0.01480	0.00019	0	0	0	0	0	1	-360	360 ;
93402	93403	0.00757	0.00871	0.00012	0	0	0	0	0	1	-360	360 ;
93403	93404	0.00975	0.01122	0.00015	0	0	0	0	0	1	-360	360 ;
93404	93405	0.01379	0.01406	0.00018	0	0	0	0	0	1	-360	360 ;
93405	93406	0.02511	0.02888	0.00039	0	0	0	0	0	1	-360	360 ;
93405	93412	0.01194	0.01374	0.00019	0	0	0	0	0	1	-360	360 ;
93406	93407	0.04283	0.04365	0.00057	0	0	0	0	0	1	-360	360 ;
93407	93408	0.01047	0.01067	0.00014	0	0	0	0	0	1	-360	360 ;
93407	93413	0.05924	0.06816	0.00093	0	0	0	0	0	1	-360	360 ;
93408	93409	0.01361	0.01387	0.00018	0	0	0	0	0	1	-360	360 ;
93409	93410	0.05598	0.05705	0.00075	0	0	0	0	0	1	-360	360 ;
93409	93418	0.00092	0.00106	0.00001	0	0	0	0	0	1	-360	360 ;
93410	93411	0.00166	0.00169	0.00002	0	0	0	0	0	1	-360	360 ;
93410	93419	0.00040	0.00046	0.00001	0	0	0	0	0	1	-360	360 ;
93413	93415	0.01658	0.01907	0.00026	0	0	0	0	0	1	-360	360 ;

93415	93416	0.00333	0.00388	0.00005	0	0	0	0	0	1	-360	360 ;
93501	93502	0.01337	0.01362	0.00018	0	0	0	0	0	1	-360	360 ;
93501	93516	0.00298	0.00303	0.00004	0	0	0	0	0	1	-360	360 ;
93502	93503	0.00497	0.00571	0.00008	0	0	0	0	0	1	-360	360 ;
93503	93504	0.00195	0.00224	0.00003	0	0	0	0	0	1	-360	360 ;
93503	93513	0.00168	0.00193	0.00003	0	0	0	0	0	1	-360	360 ;
93504	93505	0.00490	0.00500	0.00007	0	0	0	0	0	1	-360	360 ;
93504	93511	0.00244	0.00281	0.00004	0	0	0	0	0	1	-360	360 ;
93505	93506	0.00644	0.00741	0.00010	0	0	0	0	0	1	-360	360 ;
93506	93507	0.00717	0.00731	0.00010	0	0	0	0	0	1	-360	360 ;
93506	93510	0.00920	0.01058	0.00014	0	0	0	0	0	1	-360	360 ;
93507	93508	0.01996	0.02034	0.00027	0	0	0	0	0	1	-360	360 ;
93507	93509	0.00303	0.00348	0.00005	0	0	0	0	0	1	-360	360 ;
93512	93516	0.00600	0.00621	0.00008	0	0	0	0	0	1	-360	360 ;
93513	93514	0.00478	0.00549	0.00007	0	0	0	0	0	1	-360	360 ;
93513	93515	0.00107	0.00123	0.00002	0	0	0	0	0	1	-360	360 ;
93601	93602	0.01995	0.02295	0.00031	0	0	0	0	0	1	-360	360 ;
93601	93608	0.00218	0.00251	0.00003	0	0	0	0	0	1	-360	360 ;
93602	93603	0.05142	0.05240	0.00069	0	0	0	0	0	1	-360	360 ;
93602	93606	0.00244	0.00281	0.00004	0	0	0	0	0	1	-360	360 ;
93603	93604	0.00931	0.01071	0.00015	0	0	0	0	0	1	-360	360 ;
93604	93605	0.03312	0.03375	0.00044	0	0	0	0	0	1	-360	360 ;
93606	93607	0.01067	0.01246	0.00016	0	0	0	0	0	1	-360	360 ;
93701	93702	0.01638	0.04569	0.00070	0	0	0	0	0	1	-360	360 ;
93701	93704	0.00862	0.00992	0.00013	0	0	0	0	0	1	-360	360 ;
93704	93705	0.00079	0.00092	0.00001	0	0	0	0	0	1	-360	360 ;
93704	93708	0.02421	0.02827	0.00037	0	0	0	0	0	1	-360	360 ;
93705	93706	0.00028	0.00032	0.00000	0	0	0	0	0	1	-360	360 ;
93705	93707	0.00143	0.00167	0.00002	0	0	0	0	0	1	-360	360 ;
93801	93802	0.00956	0.01100	0.00015	0	0	0	0	0	1	-360	360 ;
93802	93803	0.04449	0.05119	0.00070	0	0	0	0	0	1	-360	360 ;
93803	93817	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
93901	93902	0.07217	0.08303	0.00113	0	0	0	0	0	1	-360	360 ;
93902	93903	0.06687	0.07693	0.00105	0	0	0	0	0	1	-360	360 ;
93902	93911	0.00181	0.00209	0.00003	0	0	0	0	0	1	-360	360 ;
93903	93904	0.01034	0.01190	0.00016	0	0	0	0	0	1	-360	360 ;
93903	93912	0.00032	0.00036	0.00000	0	0	0	0	0	1	-360	360 ;
93904	93905	0.01429	0.01644	0.00022	0	0	0	0	0	1	-360	360 ;
93904	93913	0.00079	0.00091	0.00001	0	0	0	0	0	1	-360	360 ;
93905	93906	0.10184	0.11717	0.00159	0	0	0	0	0	1	-360	360 ;
93905	93914	0.00346	0.00398	0.00005	0	0	0	0	0	1	-360	360 ;
93906	93915	0.00166	0.00190	0.00003	0	0	0	0	0	1	-360	360 ;
94001	94002	0.05361	0.06168	0.00084	0	0	0	0	0	1	-360	360 ;
94001	94011	0.00154	0.00177	0.00002	0	0	0	0	0	1	-360	360 ;
94002	94003	0.00760	0.00875	0.00012	0	0	0	0	0	1	-360	360 ;

7.1.2 Bus data for base case

bus	type	Pd	Qd	Gs	Bs	area	Vm	Va	baseKV	zone	Vmax	Vmin
1	2	0	0	0	0	1	1	0	230	1	1.1	0.9 ;
2	1	150	98.61	0	0	1	1	0	230	1	1.1	0.9 ;
3	2	150	98.61	0	0	1	1	0	230	1	1.1	0.9 ;
4	3	200	131.47	0	0	2	1	0	230	1	1.1	0.9 ;
5	2	0	0	0	0	2	1	0	230	1	1.1	0.9 ;
60001	1	0	0	0	29	3	1	0	66	1	1.1	0.9 ;
60002	1	0	0	0	0	3	1	0	66	2	1.1	0.9 ;
60003	1	0	0	0	0	3	1	0	66	3	1.1	0.9 ;
60101	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60102	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60103	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60104	2	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60105	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60106	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60107	1	0.9	0.134	0	0	3	1	0	66	1	1.1	0.9 ;
60108	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60109	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60110	1	2.9	0.937	0	4	3	1	0	66	1	1.1	0.9 ;
60111	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60112	2	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60113	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60114	1	0.1	0.016	0	0	3	1	0	66	1	1.1	0.9 ;
60115	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60116	1	2.9	0.406	0	0	3	1	0	66	1	1.1	0.9 ;
60117	1	10	3.31	0	4	3	1	0	66	1	1.1	0.9 ;
60125	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60126	1	5.7	1.873	0	0	3	1	0	66	1	1.1	0.9 ;
60201	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60202	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60203	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60204	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60205	1	2	0.279	0	0	3	1	0	66	1	1.1	0.9 ;
60206	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60207	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60208	1	9.1	2.998	0	0	3	1	0	66	1	1.1	0.9 ;
60209	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60210	1	0	0	0	0	3	1	0	66	1	1.1	0.9 ;
60211	1	0.4	0.059	0	0	3	1	0	66	1	1.1	0.9 ;
60212	1	3.6	0.508	0	0	3	1	0	66	1	1.1	0.9 ;

60213	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60214	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60215	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60216	1	0.1	0.021	0	0	3	1	0	66	1	1.1	0.9	;
60217	1	4.8	1.592	0	0	3	1	0	66	1	1.1	0.9	;
60218	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60219	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60221	1	0.6	0.186	0	0	3	1	0	66	1	1.1	0.9	;
60301	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60302	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60303	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60304	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60305	1	0.6	0.088	0	0	3	1	0	66	1	1.1	0.9	;
60306	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60307	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60308	1	0.2	0.029	0	0	3	1	0	66	1	1.1	0.9	;
60309	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60310	1	0.9	0.127	0	0	3	1	0	66	1	1.1	0.9	;
60312	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60313	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60314	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60315	2	0.6	0.083	0	0	3	1	0	66	1	1.1	0.9	;
60316	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60318	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60319	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60320	1	0.5	0.071	0	0	3	1	0	66	1	1.1	0.9	;
60321	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60322	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60323	1	1.3	0.183	0	0	3	1	0	66	1	1.1	0.9	;
60324	1	4.8	1.592	0	0	3	1	0	66	1	1.1	0.9	;
60325	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60326	1	4.5	1.468	0	0	3	1	0	66	1	1.1	0.9	;
60327	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60328	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60329	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60330	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60331	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60332	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60333	1	0.1	0.014	0	0	3	1	0	66	1	1.1	0.9	;
60334	2	0.3	0.109	0	0	3	1	0	66	1	1.1	0.9	;
60335	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60401	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60402	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60403	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60404	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;

60405	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60406	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60407	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60409	1	1.4	0.198	0	0	3	1	0	66	1	1.1	0.9	;
60410	1	5.9	1.936	0	0	3	1	0	66	1	1.1	0.9	;
60411	1	12	3.903	0	0	3	1	0	66	1	1.1	0.9	;
60412	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60413	1	0.3	0.042	0	0	3	1	0	66	1	1.1	0.9	;
60414	1	0.1	0.012	0	0	3	1	0	66	1	1.1	0.9	;
60415	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60416	1	1.1	0.163	0	0	3	1	0	66	1	1.1	0.9	;
60417	1	2.1	0.296	0	0	3	1	0	66	1	1.1	0.9	;
60418	1	3.6	0.508	0	0	3	1	0	66	1	1.1	0.9	;
60501	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60502	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60503	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60504	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60505	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60506	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60507	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60508	1	17	5.427	0	0	3	1	0	66	1	1.1	0.9	;
60512	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60515	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60601	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60602	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60603	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60604	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60605	1	1.1	0.152	0	0	3	1	0	66	1	1.1	0.9	;
60606	2	4.7	1.53	0	0	3	1	0	66	1	1.1	0.9	;
60607	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60609	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60610	1	1.1	0.163	0	0	3	1	0	66	1	1.1	0.9	;
60645	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60701	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60707	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60708	2	0.8	0.111	0	0	3	1	0	66	1	1.1	0.9	;
60709	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60711	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60712	1	0.5	0.073	0	0	3	1	0	66	1	1.1	0.9	;
60745	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60801	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60802	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60803	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60804	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60805	1	0.5	0.074	0	0	3	1	0	66	1	1.1	0.9	;

60806	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60807	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60808	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60809	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60810	1	1	0.147	0	0	3	1	0	66	1	1.1	0.9	;
60811	1	0.6	0.09	0	0	3	1	0	66	1	1.1	0.9	;
60815	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60817	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60818	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60819	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60821	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60822	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60823	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60825	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60827	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60828	1	19	6.139	0	0	3	1	0	66	1	1.1	0.9	;
60901	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60902	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60903	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60904	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60905	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60906	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60912	1	0.5	0.071	0	0	3	1	0	66	1	1.1	0.9	;
60914	1	1.5	0.213	0	0	3	1	0	66	1	1.1	0.9	;
60915	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60916	1	0.2	0.032	0	0	3	1	0	66	1	1.1	0.9	;
60917	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60918	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60919	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60920	1	0.1	0.016	0	0	3	1	0	66	1	1.1	0.9	;
60921	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60922	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60923	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60924	1	0.5	0.064	0	0	3	1	0	66	1	1.1	0.9	;
60925	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60926	1	1	0.142	0	0	3	1	0	66	1	1.1	0.9	;
60927	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
60929	1	3.9	0.559	0	0	3	1	0	66	1	1.1	0.9	;
61001	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61002	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61003	4	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61004	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61005	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61006	1	3.5	1.155	0	0	3	1	0	66	1	1.1	0.9	;
61007	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;

61008	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61009	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61010	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61011	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61012	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61013	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61014	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61015	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61016	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61017	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61018	1	0.2	0.034	0	0	3	1	0	66	1	1.1	0.9	;
61019	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61020	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61025	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61101	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61102	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61103	2	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61104	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61105	1	0.2	0.025	0	0	3	1	0	66	1	1.1	0.9	;
61106	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61107	1	0.7	0.101	0	0	3	1	0	66	1	1.1	0.9	;
61108	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61109	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61110	1	1.5	0.212	0	0	3	1	0	66	1	1.1	0.9	;
61111	1	1.4	0.193	0	0	3	1	0	66	1	1.1	0.9	;
61112	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61113	1	0	0	0	0	3	1	0	66	1	1.1	0.9	;
61114	1	0.3	0.038	0	0	3	1	0	66	1	1.1	0.9	;
61115	1	2.1	0.296	0	0	3	1	0	66	1	1.1	0.9	;
61201	1	3.3	1.093	0	0	3	1	0	66	2	1.1	0.9	;
61202	1	3.6	0.508	0	0	3	1	0	66	2	1.1	0.9	;
61203	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61204	2	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61205	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61208	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61209	1	1	0.141	0	0	3	1	0	66	2	1.1	0.9	;
61210	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61211	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61301	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61302	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61303	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61304	1	13	4.247	0	0	3	1	0	66	2	1.1	0.9	;
61305	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61306	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61307	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;

61308	1	3.4	0.482	0	0	3	1	0	66	2	1.1	0.9	;
61309	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61310	2	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61311	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61312	2	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61313	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61314	2	1.4	0.203	0	0	3	1	0	66	2	1.1	0.9	;
61315	1	7.3	2.404	0	0	3	1	0	66	2	1.1	0.9	;
61401	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61402	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61403	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61404	1	11	3.716	0	0	3	1	0	66	2	1.1	0.9	;
61405	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61406	2	1.1	0.15	0	0	3	1	0	66	2	1.1	0.9	;
61407	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61408	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61409	1	4.7	1.53	0	0	3	1	0	66	2	1.1	0.9	;
61410	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61411	1	0.4	0.058	0	0	3	1	0	66	2	1.1	0.9	;
61412	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61413	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61501	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61502	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61503	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61504	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61505	1	1	0.142	0	0	3	1	0	66	2	1.1	0.9	;
61506	1	7.4	2.436	0	0	3	1	0	66	2	1.1	0.9	;
61601	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61602	1	0	0	0	0	3	1	0	66	2	1.1	0.9	;
61603	1	7.4	2.436	0	0	3	1	0	66	2	1.1	0.9	;
61708	1	14	4.549	0	0	3	1	0	66	3	1.1	0.9	;
61711	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61713	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61714	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61715	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61716	1	0.8	0.12	0	0	3	1	0	66	3	1.1	0.9	;
61718	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61719	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61720	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61722	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61726	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61728	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61730	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61732	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61733	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;

61735	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61737	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61739	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61740	4	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61819	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61820	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61821	1	2.7	0.381	0	0	3	1	0	66	3	1.1	0.9	;
61822	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61823	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61824	1	0.5	0.076	0	0	3	1	0	66	3	1.1	0.9	;
61825	1	0.2	0.034	0	0	3	1	0	66	3	1.1	0.9	;
61826	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61827	1	3.1	0.44	0	0	3	1	0	66	3	1.1	0.9	;
61828	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61829	1	5.7	0.815	0	0	3	1	0	66	3	1.1	0.9	;
61830	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61831	1	0.2	0.023	0	0	3	1	0	66	3	1.1	0.9	;
61832	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61833	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61834	1	5.5	0.787	0	0	3	1	0	66	3	1.1	0.9	;
61835	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61836	1	0.4	0.051	0	0	3	1	0	66	3	1.1	0.9	;
61837	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61838	1	2.7	0.381	0	0	3	1	0	66	3	1.1	0.9	;
61839	1	0	0	0	0	3	1	0	66	3	1.1	0.9	;
61840	1	3.1	1.03	0	0	3	1	0	66	3	1.1	0.9	;
90001	1	0	0	0	30	4	1	0	66	1	1.1	0.9	;
90002	1	0	0	0	30	4	1	0	66	2	1.1	0.9	;
90003	1	0	0	0	0	4	1	0	66	3	1.1	0.9	;
90004	1	0	0	0	0	4	1	0	66	4	1.1	0.9	;
90005	1	0	0	0	0	4	1	0	66	5	1.1	0.9	;
90101	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90103	1	19	2.741	0	0	4	1	0	66	1	1.1	0.9	;
90201	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90202	1	4.6	0.66	0	0	4	1	0	66	1	1.1	0.9	;
90203	1	19	2.741	0	0	4	1	0	66	1	1.1	0.9	;
90301	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90302	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90303	1	0.7	0.098	0	0	4	1	0	66	1	1.1	0.9	;
90401	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90402	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90403	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90404	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90405	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90406	1	0.4	0.056	0	0	4	1	0	66	1	1.1	0.9	;

90407	1	1.1	0.375	0	0	4	1	0	66	1	1.1	0.9	;
90408	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90410	1	12	1.742	0	0	4	1	0	66	1	1.1	0.9	;
90411	1	2.9	0.968	0	0	4	1	0	66	1	1.1	0.9	;
90412	1	2.7	0.386	0	0	4	1	0	66	1	1.1	0.9	;
90413	2	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90506	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90507	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90508	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90509	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90510	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90511	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90521	1	2.6	0.366	0	0	4	1	0	66	1	1.1	0.9	;
90522	1	2.7	0.381	0	0	4	1	0	66	1	1.1	0.9	;
90523	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90524	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90525	1	0.7	0.093	0	0	4	1	0	66	1	1.1	0.9	;
90526	1	2.1	0.687	0	0	4	1	0	66	1	1.1	0.9	;
90527	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90528	1	4.4	0.621	0	0	4	1	0	66	1	1.1	0.9	;
90529	1	2.5	0.353	0	0	4	1	0	66	1	1.1	0.9	;
90530	2	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90532	2	6.5	0.933	0	0	4	1	0	66	1	1.1	0.9	;
90533	1	0.2	0.03	0	0	4	1	0	66	1	1.1	0.9	;
90534	1	13	4.153	0	0	4	1	0	66	1	1.1	0.9	;
90538	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90601	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90602	2	0.1	0.02	0	0	4	1	0	66	1	1.1	0.9	;
90603	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90604	1	1.7	0.245	0	0	4	1	0	66	1	1.1	0.9	;
90605	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90607	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90608	1	13	4.215	0	0	4	1	0	66	1	1.1	0.9	;
90701	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90702	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90703	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90704	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90705	1	2.6	0.366	0	0	4	1	0	66	1	1.1	0.9	;
90706	1	2.4	0.345	0	0	4	1	0	66	1	1.1	0.9	;
90707	1	1.6	0.223	0	0	4	1	0	66	1	1.1	0.9	;
90708	1	17	5.636	0	0	4	1	0	66	1	1.1	0.9	;
90801	1	17	2.449	0	0	4	1	0	66	1	1.1	0.9	;
90802	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90803	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90804	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;

90805	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90806	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90807	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90810	4	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90902	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90903	1	17	5.636	0	0	4	1	0	66	1	1.1	0.9	;
90904	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90905	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
90906	1	2.7	0.381	0	0	4	1	0	66	1	1.1	0.9	;
90907	1	0.8	0.12	0	0	4	1	0	66	1	1.1	0.9	;
90910	1	0.7	0.095	0	0	4	1	0	66	1	1.1	0.9	;
91001	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91002	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91014	1	1.2	0.178	0	0	4	1	0	66	1	1.1	0.9	;
91015	1	2.9	0.413	0	0	4	1	0	66	1	1.1	0.9	;
91016	1	1.9	0.269	0	0	4	1	0	66	1	1.1	0.9	;
91017	1	26	8.449	0	0	4	1	0	66	1	1.1	0.9	;
91103	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91104	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91105	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91118	1	0.4	0.055	0	0	4	1	0	66	1	1.1	0.9	;
91119	1	1.9	0.271	0	0	4	1	0	66	1	1.1	0.9	;
91120	1	20	6.588	0	0	4	1	0	66	1	1.1	0.9	;
91138	1	0	0	0	0	4	1	0	66	1	1.1	0.9	;
91201	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91202	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91203	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91204	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91205	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91206	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91207	2	3.3	1.093	0	0	4	1	0	66	2	1.1	0.9	;
91208	1	0.7	0.1	0	0	4	1	0	66	2	1.1	0.9	;
91209	1	1.1	0.152	0	0	4	1	0	66	2	1.1	0.9	;
91210	1	0.7	0.095	0	0	4	1	0	66	2	1.1	0.9	;
91211	1	1	0.135	0	0	4	1	0	66	2	1.1	0.9	;
91301	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91302	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91303	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91304	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91311	1	1.1	0.375	0	0	4	1	0	66	2	1.1	0.9	;
91313	1	0.1	0.02	0	0	4	1	0	66	2	1.1	0.9	;
91401	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91402	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91403	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;
91404	1	0	0	0	0	4	1	0	66	2	1.1	0.9	;

91408	1	0.1	0.017	0	0	4	1	0	66	2	1.1	0.9 ;
91409	1	1.8	0.261	0	0	4	1	0	66	2	1.1	0.9 ;
91410	1	1.8	0.251	0	0	4	1	0	66	2	1.1	0.9 ;
91501	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91502	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91503	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91504	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91508	1	0.6	0.091	0	0	4	1	0	66	2	1.1	0.9 ;
91509	1	0.8	0.11	0	0	4	1	0	66	2	1.1	0.9 ;
91510	1	7.5	1.069	0	0	4	1	0	66	2	1.1	0.9 ;
91601	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91602	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91603	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91604	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91605	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91606	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91607	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91609	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91610	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91611	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91612	1	13	4.403	0	5	4	1	0	66	2	1.1	0.9 ;
91613	1	3.4	1.124	0	1	4	1	0	66	2	1.1	0.9 ;
91614	2	0	0.007	0	0	4	1	0	66	2	1.1	0.9 ;
91615	1	0.3	0.037	0	0	4	1	0	66	2	1.1	0.9 ;
91701	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91702	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91704	1	8	2.623	0	0	4	1	0	66	2	1.1	0.9 ;
91705	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91706	2	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91812	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91813	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91835	1	35	11.553	0	0	4	1	0	66	2	1.1	0.9 ;
91836	1	0.8	0.114	0	0	4	1	0	66	2	1.1	0.9 ;
91837	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
91908	1	13	4.215	0	0	4	1	0	66	2	1.1	0.9 ;
91909	1	0	0	0	0	4	1	0	66	2	1.1	0.9 ;
92001	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92002	1	3.3	1.093	0	0	4	1	0	66	3	1.1	0.9 ;
92003	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92004	2	2.3	0.749	0	0	4	1	0	66	3	1.1	0.9 ;
92005	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92006	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92007	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92008	1	2.1	0.305	0	0	4	1	0	66	3	1.1	0.9 ;
92009	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;

92010	1	1.2	0.169	0	0	4	1	0	66	3	1.1	0.9 ;
92011	1	1.5	0.217	0	0	4	1	0	66	3	1.1	0.9 ;
92101	1	16	2.24	0	0	4	1	0	66	3	1.1	0.9 ;
92201	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92202	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92203	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92204	1	7.2	2.373	0	0	4	1	0	66	3	1.1	0.9 ;
92205	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92206	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92207	1	1.6	0.231	0	0	4	1	0	66	3	1.1	0.9 ;
92208	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92209	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92210	1	4.3	1.405	0	0	4	1	0	66	3	1.1	0.9 ;
92211	2	2.7	0.381	0	0	4	1	0	66	3	1.1	0.9 ;
92212	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92213	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92214	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92215	1	7.2	2.373	0	2	4	1	0	66	3	1.1	0.9 ;
92301	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92302	1	13	1.854	0	0	4	1	0	66	3	1.1	0.9 ;
92401	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92402	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92403	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92404	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92405	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92406	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92407	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92410	1	0.3	0.048	0	0	4	1	0	66	3	1.1	0.9 ;
92411	1	1.5	0.22	0	0	4	1	0	66	3	1.1	0.9 ;
92412	1	0.7	0.104	0	0	4	1	0	66	3	1.1	0.9 ;
92501	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92502	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92503	1	2.1	0.687	0	0	4	1	0	66	3	1.1	0.9 ;
92504	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92505	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92506	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92507	1	2.8	0.906	0	0	4	1	0	66	3	1.1	0.9 ;
92510	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92511	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92512	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92513	1	0.4	0.057	0	0	4	1	0	66	3	1.1	0.9 ;
92601	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92602	1	3.5	0.498	0	0	4	1	0	66	3	1.1	0.9 ;
92701	1	7.6	2.498	0	0	4	1	0	66	3	1.1	0.9 ;
92805	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;

92806	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92807	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92811	1	4.5	1.468	0	0	4	1	0	66	3	1.1	0.9 ;
92812	1	3.2	0.462	0	0	4	1	0	66	3	1.1	0.9 ;
92901	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92902	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92903	1	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92904	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92905	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
92906	2	0	0	0	0	4	1	0	66	3	1.1	0.9 ;
93001	2	2.8	0.396	0	0	4	1	0	66	4	1.1	0.9 ;
93101	1	4.8	1.561	0	0	4	1	0	66	4	1.1	0.9 ;
93201	1	9.6	1.374	0	0	4	1	0	66	4	1.1	0.9 ;
93305	1	0	0	0	0	4	1	0	66	4	1.1	0.9 ;
93306	1	0	0	0	0	4	1	0	66	4	1.1	0.9 ;
93307	1	0	0	0	0	4	1	0	66	4	1.1	0.9 ;
93308	1	1.2	0.174	0	0	4	1	0	66	4	1.1	0.9 ;
93309	1	0.9	0.281	0	0	4	1	0	66	4	1.1	0.9 ;
93310	1	0.8	0.114	0	0	4	1	0	66	4	1.1	0.9 ;
93401	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93402	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93403	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93404	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93405	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93406	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93407	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93408	1	7.8	2.56	0	0	4	1	0	66	5	1.1	0.9 ;
93409	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93410	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93411	1	10	3.435	0	0	4	1	0	66	5	1.1	0.9 ;
93412	1	1.6	0.229	0	0	4	1	0	66	5	1.1	0.9 ;
93413	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93415	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93416	1	3.5	0.503	0	0	4	1	0	66	5	1.1	0.9 ;
93418	1	1.7	0.247	0	0	4	1	0	66	5	1.1	0.9 ;
93419	1	0.9	0.129	0	0	4	1	0	66	5	1.1	0.9 ;
93501	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93502	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93503	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93504	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93505	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93506	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93507	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93508	1	0.4	0.059	0	0	4	1	0	66	5	1.1	0.9 ;
93509	1	0.6	0.084	0	0	4	1	0	66	5	1.1	0.9 ;

93510	1	0.6	0.085	0	0	4	1	0	66	5	1.1	0.9 ;
93511	1	1.2	0.173	0	0	4	1	0	66	5	1.1	0.9 ;
93512	1	16	5.308	0	0	4	1	0	66	5	1.1	0.9 ;
93513	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93514	1	5.9	0.843	0	0	4	1	0	66	5	1.1	0.9 ;
93515	1	2.5	0.355	0	0	4	1	0	66	5	1.1	0.9 ;
93516	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93601	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93602	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93603	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93604	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93605	1	4.9	1.624	0	0	4	1	0	66	5	1.1	0.9 ;
93606	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93607	1	3.8	0.547	0	0	4	1	0	66	5	1.1	0.9 ;
93608	1	7.9	2.592	0	0	4	1	0	66	5	1.1	0.9 ;
93701	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93702	2	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93704	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93705	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93706	1	1.8	0.257	0	0	4	1	0	66	5	1.1	0.9 ;
93707	1	4.1	1.343	0	0	4	1	0	66	5	1.1	0.9 ;
93708	1	3.1	0.442	0	0	4	1	0	66	5	1.1	0.9 ;
93801	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93802	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93803	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93817	1	0.6	0.085	0	0	4	1	0	66	5	1.1	0.9 ;
93901	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93902	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93903	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93904	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93905	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93906	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
93911	1	6.7	2.186	0	0	4	1	0	66	5	1.1	0.9 ;
93912	1	1.5	0.213	0	0	4	1	0	66	5	1.1	0.9 ;
93913	1	4.3	1.405	0	0	4	1	0	66	5	1.1	0.9 ;
93914	1	2.4	0.34	0	0	4	1	0	66	5	1.1	0.9 ;
93915	1	4.3	1.405	0	0	4	1	0	66	5	1.1	0.9 ;
94001	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
94002	1	0	0	0	0	4	1	0	66	5	1.1	0.9 ;
94003	1	2.9	0.968	0	0	4	1	0	66	5	1.1	0.9 ;
94010	1	1.5	0.212	0	0	4	1	0	66	5	1.1	0.9 ;
94011	2	0.5	0.066	0	0	4	1	0	66	5	1.1	0.9 ;

7.1.3 Generation data for base case.

bus	Pg	Qg	Qmax	Qmin	Vg	mBase	status	Pmax	Pmin
1	40	0	30	-30	1	100	1	40	0 ;
1	170	0	127.5	-127.5	1	100	1	170	0 ;
3	350	0	262.5	-262.5	1	100	1	350	0 ;
4	0	0	150	-150	1	100	1	200	0 ;
5	320	0	240	-240	1	100	1	320	0 ;
60104	7.8	0	0	0	1	100	1	7.8	0 ;
60112	1.92	0	0	0	1	100	1	1.92	0 ;
60315	0.032	0	0	0	1	100	1	0.03	0 ;
60327	3.48	0	0	0	1	100	1	3.48	0 ;
60330	2.42	0	0	0	1	100	1	2.42	0 ;
60334	5.76	0	0	0	1	100	1	5.76	0 ;
60606	2.42	0	0	0	1	100	1	2.42	0 ;
60708	2.4	0	0	0	1	100	1	2.4	0 ;
61011	1.84	0	0	0	1	100	1	1.84	0 ;
61012	4.5	0	0	0	1	100	1	4.5	0 ;
61016	5.6	0	0	0	1	100	1	5.6	0 ;
61020	3.94	0	0	0	1	100	1	3.94	0 ;
61103	1.92	0	0	0	1	100	1	1.92	0 ;
61204	4.2	0	0	0	1	100	1	4.2	0 ;
61310	3.68	0	0	0	1	100	1	3.68	0 ;
61312	3.75	0	0	0	1	100	1	3.75	0 ;
61314	0.6	0	0	0	1	100	1	0.6	0 ;
61406	2.12	0	0	0	1	100	1	2.12	0 ;
90413	3.75	0	0	0	1	100	1	3.75	0 ;
90530	5	0	0	0	1	100	1	5	0 ;
90532	5.96	0	0	0	1	100	1	5.96	0 ;
90602	0.82	0	0	0	1	100	1	0.82	0 ;
91207	6.7	0	0	0	1	100	1	6.7	0 ;
91614	4.4	0	0	0	1	100	1	4.4	0 ;
91706	8.88	0	0	0	1	100	1	8.88	0 ;
92003	4.8	0	0	0	1	100	1	4.8	0 ;
92004	6.8	0	0	0	1	100	1	6.8	0 ;
92206	4.12	0	0	0	1	100	1	4.12	0 ;
92208	6	0	0	0	1	100	1	6	0 ;
92211	3.78	0	0	0	1	100	1	3.78	0 ;
92510	4	0	0	0	1	100	1	4	0 ;
92511	4	0	0	0	1	100	1	4	0 ;
92512	4.5	0	0	0	1	100	1	4.5	0 ;
92904	24.6	0	0	0	1	100	1	24.6	0 ;
92905	24.6	0	0	0	1	100	1	24.6	0 ;
92906	19.8	0	0	0	1	100	1	19.8	0 ;
93001	8.79	0	0	0	1	100	1	8.79	0 ;

93702	18	0	0	0	1	100	1	18	0	;
94011	1	0	0	0	1	100	1	1	0	;

7.2 Matpower output from power flow simulation

7.2.1 M(Y-1) Maximum demand

System Summary	
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How many?		How much?	P (MW)	Q (MVar)
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	1262.9	482.4
Loads	199	Load	1248.1	514.3
Fixed	199	Fixed	1248.1	514.3
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.2
Branches	576	Losses (I ² * Z)	14.83	94.09
Transformers	0	Branch Charging (inj)	-	22.9
Inter-ties	11	Total Inter-tie Flow	897.5	61.9
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.944 p.u. @ bus 93411	1.004 p.u. @ bus 90002
Voltage Angle	-8.82 deg @ bus 91613	3.86 deg @ bus 92904
P Losses (I ² *R)	-	1.22 MW @ line 4-5
Q Losses (I ² *X)	-	21.54 MVar @ line 4-90001

Area Summary	
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Area Num	# of Buses	# of Gens Total	# of Gens Online	# of Loads Total	# of Loads Fixed	# of Loads Disp	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5
Tot:	576	44	44	199	199	0	8	576	0	11

Area Num	Total Gen Capacity MW	Total Gen Capacity MVar	On-line Gen Capacity MW	On-line Gen Capacity MVar	Generation MW	Generation MVar
1	560.0	-420.0 to 420.0	560.0	-420.0 to 420.0	560.0	205.8
2	520.0	-390.0 to 390.0	520.0	-390.0 to 390.0	474.2	178.1
3	58.4	0.0 to 0.0	58.4	0.0 to 0.0	58.4	27.8
4	170.3	0.0 to 0.0	170.3	0.0 to 0.0	170.3	70.7
Tot:	1308.7	-810.0 to 810.0	1308.7	-810.0 to 810.0	1262.9	482.4

Area Num	Disp Load MW	Cap Load MVar	Disp Load MW	Load MVar	Fixed Load MW	Load MVar	Total Load MW	Total Load MVar
1	-0.0	-0.0	-0.0	-0.0	291.0	191.3	291.0	191.3

2	-0.0	-0.0	-0.0	-0.0	194.0	127.5	194.0	127.5
3	-0.0	-0.0	-0.0	-0.0	243.7	66.4	243.7	66.4
4	-0.0	-0.0	-0.0	-0.0	519.3	129.1	519.3	129.1
Tot:	-0.0	-0.0	-0.0	-0.0	1248.1	514.3	1248.1	514.3

Area Num	Shunt MW	Inj MVar	Branch Charging	Series MW	Losses MVar	Net MW	Export MVar
1	-0.0	0.0	4.8	1.27	19.04	267.7	-2.0
2	-0.0	0.0	2.9	1.72	34.54	278.5	16.7
3	-0.0	35.9	6.2	4.69	11.57	-190.0	-8.0
4	-0.0	67.2	9.0	7.14	28.94	-356.2	-11.1
Tot:	-0.0	103.2	22.9	14.83	94.09	-	-

7.2.2 M(Y-1) Medium demand

System Summary	
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How many?	How much?	P (MW)	Q (MVar)	
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	1068.5	386.5
Loads	199	Load	1056.9	435.3
Fixed	199	Fixed	1056.9	435.3
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.4
Branches	576	Losses (I ² * Z)	11.60	77.48
Transformers	0	Branch Charging (inj)	-	22.9
Inter-ties	11	Total Inter-tie Flow	852.9	63.1
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.953 p.u. @ bus 93411	1.005 p.u. @ bus 90002
Voltage Angle	-8.61 deg @ bus 91613	2.52 deg @ bus 5
P Losses (I ² *R)	-	1.37 MW @ line 4-5
Q Losses (I ² *X)	-	15.48 MVar @ line 4-90001

Area Summary	
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Area Num	# of Buses	# of Gens Total	# of Gens Online	# of Loads Total	# of Loads Fixed	# of Loads Disp	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5
Tot:	576	44	44	199	199	0	8	576	0	11

Area Num	Total Gen Capacity MW	Total Gen Capacity MVar	On-line Gen Capacity MW	On-line Gen Capacity MVar	Generation MW	Generation MVar
1	560.0	-420.0 to 420.0	560.0	-420.0 to 420.0	554.6	163.4
2	520.0	-390.0 to 390.0	520.0	-390.0 to 390.0	320.0	159.4
3	58.4	0.0 to 0.0	58.4	0.0 to 0.0	49.3	16.4

4	170.3	0.0 to 0.0	170.3	0.0 to 0.0	144.6	47.4
Tot:	1308.7	-810.0 to 810.0	1308.7	-810.0 to 810.0	1068.5	386.5

Area Num	Disp MW	Load Cap MVAR	Disp MW	Load MVAR	Fixed MW	Load MVAR	Total MW	Load MVAR
1	-0.0	-0.0	-0.0	-0.0	245.5	161.4	245.5	161.4
2	-0.0	-0.0	-0.0	-0.0	164.7	108.3	164.7	108.3
3	-0.0	-0.0	-0.0	-0.0	205.6	56.0	205.6	56.0
4	-0.0	-0.0	-0.0	-0.0	441.0	109.6	441.0	109.6
Tot:	-0.0	-0.0	-0.0	-0.0	1056.9	435.3	1056.9	435.3

Area Num	Shunt MW	Inj MVAR	Branch Charging	Series MW	Losses MVAR	Net MW	Export MVAR
1	-0.0	0.0	4.8	1.16	16.03	307.9	-11.5
2	-0.0	0.0	2.9	2.01	32.53	153.2	19.2
3	-0.0	36.0	6.3	3.31	8.16	-159.7	-5.6
4	-0.0	67.4	9.0	5.11	20.75	-301.5	-6.6
Tot:	-0.0	103.4	22.9	11.60	77.48	-	-

7.2.3 M(Y-1) Minimum demand

System Summary	
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How many?		How much?	P (MW)	Q (MVar)
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	625.9	176.3
Loads	199	Load	619.9	257.8
Fixed	199	Fixed	619.9	257.8
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.9
Branches	576	Losses (I ² * Z)	5.99	45.38
Transformers	0	Branch Charging (inj)	-	23.0
Inter-ties	11	Total Inter-tie Flow	625.9	58.0
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.975 p.u. @ bus 93411	1.007 p.u. @ bus 90002
Voltage Angle	-8.88 deg @ bus 60117	0.00 deg @ bus 5
P Losses (I ² *R)	-	1.00 MW @ line 1-2
Q Losses (I ² *X)	-	9.98 MVar @ line 1-2

Area Summary	
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Area Num	# of Buses	# of Total Gens	# of Online Gens	# of Total Loads	# of Fixed Loads	# of Disp Loads	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5

Tot:	576	44	44	199	199	0	8	576	0	11
Area Num	Total Gen MW	Capacity MVar		On-line Gen MW	Capacity MVar			Generation MW		MVar
1	560.0	-420.0 to 420.0		560.0	-420.0 to 420.0			210.0		120.9
2	520.0	-390.0 to 390.0		520.0	-390.0 to 390.0			304.9		66.3
3	58.4	0.0 to 0.0		58.4	0.0 to 0.0			31.1		-4.9
4	170.3	0.0 to 0.0		170.3	0.0 to 0.0			80.0		-6.0
Tot:	1308.7	-810.0 to 810.0		1308.7	-810.0 to 810.0			625.9		176.3

Area Num	Disp MW	Load MVar	Cap MVar	Disp MW	Load MVar	Fixed MW	Load MVar	Total MW	Load MVar
1	-0.0	-0.0	-0.0	-0.0	-0.0	155.1	102.0	155.1	102.0
2	-0.0	-0.0	-0.0	-0.0	-0.0	91.1	59.9	91.1	59.9
3	-0.0	-0.0	-0.0	-0.0	-0.0	129.9	35.4	129.9	35.4
4	-0.0	-0.0	-0.0	-0.0	-0.0	243.9	60.6	243.9	60.6
Tot:	-0.0	-0.0	-0.0	-0.0	-0.0	619.9	257.8	619.9	257.8

Area Num	Shunt MW	Inj MVar	Branch Charging	Series MW	Losses MVar	Net MW	Export MVar
1	-0.0	0.0	4.8	1.62	17.92	53.3	3.6
2	-0.0	0.0	2.9	1.41	17.85	212.4	-10.8
3	-0.0	36.1	6.3	1.32	3.22	-100.1	-1.2
4	-0.0	67.8	9.1	1.65	6.38	-165.5	3.8
Tot:	-0.0	103.9	23.0	5.99	45.38	-	-

7.2.4 M(Y) Maximum demand

System Summary

How many?		How much?	P (MW)	Q (MVar)
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	1302.2	502.5
Loads	199	Load	1286.7	530.2
Fixed	199	Fixed	1286.7	530.2
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.1
Branches	576	Losses (I ² * Z)	15.48	98.26
Transformers	0	Branch Charging (inj)	-	22.9
Inter-ties	11	Total Inter-tie Flow	905.4	61.4
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.942 p.u. @ bus 93411	1.004 p.u. @ bus 90002
Voltage Angle	-9.17 deg @ bus 91613	3.71 deg @ bus 92904
P Losses (I ² *R)	-	1.18 MW @ line 4-5
Q Losses (I ² *X)	-	23.02 MVar @ line 4-90001

Area Summary

Area Num	# of Buses	# of Total Gens	# of Online Gens	# of Total Loads	# of Fixed Loads	# of Disp Loads	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5
Tot:	576	44	44	199	199	0	8	576	0	11

Area Num	Total Gen Capacity MW	Gen Capacity MVar	On-line Gen Capacity MW	Gen Capacity MVar	Generation MW	Generation MVar
1	560.0	-420.0 to 420.0	560.0	-420.0 to 420.0	560.0	214.6
2	520.0	-390.0 to 390.0	520.0	-390.0 to 390.0	513.5	181.2
3	58.4	0.0 to 0.0	58.4	0.0 to 0.0	58.4	30.4
4	170.3	0.0 to 0.0	170.3	0.0 to 0.0	170.3	76.3
Tot:	1308.7	-810.0 to 810.0	1308.7	-810.0 to 810.0	1302.2	502.5

Area Num	Disp Load MW	Load Cap MVar	Disp Load MW	Load MVar	Fixed Load MW	Load MVar	Total Load MW	Load MVar
1	-0.0	-0.0	-0.0	-0.0	300.0	197.2	300.0	197.2
2	-0.0	-0.0	-0.0	-0.0	200.0	131.5	200.0	131.5
3	-0.0	-0.0	-0.0	-0.0	251.3	68.4	251.3	68.4
4	-0.0	-0.0	-0.0	-0.0	535.4	133.1	535.4	133.1
Tot:	-0.0	-0.0	-0.0	-0.0	1286.7	530.2	1286.7	530.2

Area Num	Shunt MW	Inj MVar	Branch Charging	Series Losses MW	Losses MVar	Net Export MW	Export MVar
1	-0.0	0.0	4.8	1.32	19.99	258.7	-0.0
2	-0.0	0.0	2.9	1.67	35.17	311.8	15.2
3	-0.0	35.9	6.2	4.96	12.40	-197.8	-8.3
4	-0.0	67.2	9.0	7.54	30.70	-372.6	-11.3
Tot:	-0.0	103.1	22.9	15.48	98.26	-	-

7.2.5 M(Y) Medium demand

System Summary	
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How many?	How much?	P (MW)	Q (MVar)	
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	1101.6	402.7
Loads	199	Load	1089.6	448.8
Fixed	199	Fixed	1089.6	448.8
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.4
Branches	576	Losses (I ² * Z)	12.03	80.23
Transformers	0	Branch Charging (inj)	-	22.9
Inter-ties	11	Total Inter-tie Flow	863.2	62.7
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.951 p.u. @ bus 93411	1.005 p.u. @ bus 90002
Voltage Angle	-7.75 deg @ bus 91613	3.65 deg @ bus 5
P Losses (I ² *R)	-	1.35 MW @ line 4-5
Q Losses (I ² *X)	-	16.54 MVar @ line 4-90001

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| Area Summary |
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Area Num	# of Buses	# of Gens Total	# of Gens Online	# of Loads Total	# of Loads Fixed	# of Loads Disp	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5
Tot:	576	44	44	199	199	0	8	576	0	11

Area Num	Total Gen Capacity MW	Total Gen Capacity MVar	On-line Gen Capacity MW	On-line Gen Capacity MVar	Generation MW	Generation MVar
1	560.0	-420.0 to 420.0	560.0	-420.0 to 420.0	560.0	169.9
2	520.0	-390.0 to 390.0	520.0	-390.0 to 390.0	347.7	162.4
3	58.4	0.0 to 0.0	58.4	0.0 to 0.0	49.3	18.5
4	170.3	0.0 to 0.0	170.3	0.0 to 0.0	144.6	51.9
Tot:	1308.7	-810.0 to 810.0	1308.7	-810.0 to 810.0	1101.6	402.7

Area Num	Disp Load MW	Cap MVar	Disp Load MW	Load MVar	Fixed Load MW	Load MVar	Total Load MW	Load MVar
1	-0.0	-0.0	-0.0	-0.0	253.1	166.4	253.1	166.4
2	-0.0	-0.0	-0.0	-0.0	169.8	111.6	169.8	111.6
3	-0.0	-0.0	-0.0	-0.0	212.0	57.7	212.0	57.7
4	-0.0	-0.0	-0.0	-0.0	454.7	113.0	454.7	113.0
Tot:	-0.0	-0.0	-0.0	-0.0	1089.6	448.8	1089.6	448.8

Area Num	Shunt MW	Inj MVar	Branch Charging	Series Losses MW	Losses MVar	Net Export MW	MVar
1	-0.0	0.0	4.8	1.17	16.50	305.7	-10.4
2	-0.0	0.0	2.9	1.97	32.99	175.9	18.5
3	-0.0	36.0	6.3	3.50	8.74	-166.2	-5.7
4	-0.0	67.4	9.0	5.39	22.00	-315.4	-6.8
Tot:	-0.0	103.4	22.9	12.03	80.23	-	-

7.2.6 M(Y) Minimum demand

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| System Summary |
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How many?		How much?	P (MW)	Q (MVar)
Buses	576	Total Gen Capacity	1308.7	-810.0 to 810.0
Generators	44	On-line Capacity	1308.7	-810.0 to 810.0
Committed Gens	44	Generation (actual)	645.4	187.0
Loads	199	Load	639.1	265.8

Fixed	199	Fixed	639.1	265.8
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	8	Shunt (inj)	-0.0	103.9
Branches	576	Losses (I ² * Z)	6.32	48.16
Transformers	0	Branch Charging (inj)	-	23.0
Inter-ties	11	Total Inter-tie Flow	648.5	59.5
Areas	4			

	Minimum	Maximum
Voltage Magnitude	0.974 p.u. @ bus 93411	1.007 p.u. @ bus 90002
Voltage Angle	-4.84 deg @ bus 60117	4.35 deg @ bus 5
P Losses (I ² *R)	-	1.04 MW @ line 1-2
Q Losses (I ² *X)	-	10.45 MVar @ line 1-2

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| Area Summary |
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Area Num	# of Buses	# of Gens Total	# of Gens Online	# of Loads Total	# of Loads Fixed	# of Loads Disp	# of Shunt	# of Brchs	# of Xfmrs	# of Ties
1	3	3	3	2	2	0	0	2	0	6
2	2	2	2	1	1	0	0	1	0	8
3	285	18	18	82	82	0	3	281	0	3
4	286	21	21	114	114	0	5	281	0	5
Tot:	576	44	44	199	199	0	8	576	0	11

Area Num	Total Gen Capacity MW	Total Gen Capacity MVar	On-line Gen Capacity MW	On-line Gen Capacity MVar	Generation MW	Generation MVar
1	560.0	-420.0 to 420.0	560.0	-420.0 to 420.0	214.4	125.6
2	520.0	-390.0 to 390.0	520.0	-390.0 to 390.0	320.0	69.0
3	58.4	0.0 to 0.0	58.4	0.0 to 0.0	31.1	-3.7
4	170.3	0.0 to 0.0	170.3	0.0 to 0.0	80.0	-3.8
Tot:	1308.7	-810.0 to 810.0	1308.7	-810.0 to 810.0	645.4	187.0

Area Num	Disp Load MW	Disp Load Cap MVar	Disp Load MW	Disp Load MVar	Fixed Load MW	Fixed Load MVar	Total Load MW	Total Load MVar
1	-0.0	-0.0	-0.0	-0.0	159.9	105.1	159.9	105.1
2	-0.0	-0.0	-0.0	-0.0	93.9	61.7	93.9	61.7
3	-0.0	-0.0	-0.0	-0.0	133.9	36.5	133.9	36.5
4	-0.0	-0.0	-0.0	-0.0	251.4	62.5	251.4	62.5
Tot:	-0.0	-0.0	-0.0	-0.0	639.1	265.8	639.1	265.8

Area Num	Shunt MW	Inj MVar	Branch Charging	Series Losses MW	Series Losses MVar	Net Export MW	Net Export MVar
1	-0.0	0.0	4.8	1.70	18.88	52.8	4.2
2	-0.0	0.0	2.9	1.50	19.08	224.6	-11.2
3	-0.0	36.1	6.3	1.39	3.45	-104.2	-1.2
4	-0.0	67.8	9.1	1.72	6.75	-173.2	3.8
Tot:	-0.0	103.9	23.0	6.32	48.16	-	-