A New Power Generating Units Dynamic Model

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Abstract: This paper presents a new power generating unit dynamic model that requires only one experiment for parameter identification. This model represents boiler pressure effects as a differentiating process with its subsequent identification through a new approach. In addition, a novel procedure is proposed for the model parameter correction in case that the identification test is not sufficiently informative. This dynamic model is developed in the vicinity of the steady-state operation mode and can be used for load-frequency control tuning or its redesign, for Automatic Generation Control purposes, as well as a base for real-time simulators for dispatcher training. The modeling of 575MW power units of the IEC (Israel) is fulfilled through implementation of this model yielding sufficiently good results.

Keywords: Boiler-turbine models, Transfer function identification, Power system modeling

1. INTRODUCTION

We consider a Load-Frequency Control Unit Model (LFCUM) of a steam generation unit [3] that models unit load responses to net-frequency deviations and to load set point changes in vicinity of steady-state mode.

Such dynamic model is needed first for the analysis of the "primary grid – frequency control". Actually, the LFCUM is required to keep the dynamic response quality [11] by tuning of Unit Coordinated Control which influences directly on this response in the vicinity of ±(5-10)% of the steady–state mode parameters. This problem is especially urgent for networks with limited energy reserve in particular for the Israeli networks. Furthermore, LFCUM is needed for adequate description of the power unit's required by the Automatic Generation Control (AGC) [5]. In addition, such LFCUM may also be used as a part of a real time simulator for operation staff and dispatcher training.

General nonlinear models for steam generation plant (see, for example, [1,4,9]) are related to physical and construction data. Obtaining of these data needed for accurate model calculation may be problematic for some working units. Actually, these models are often applied as a basis for developing corresponding LFCUM through identification technique [2,10,12]. Based on this approach, the LFCUM is developed in [3] according to the following principles:

- The LFCUM identification requires three relatively simple experiments.
- A transfer function identification method is used providing the model order reduction as a part of its own identification procedure. This identification is based on a test exited by a deterministic signal, which is used instead of the pseudo-random binary sequence (PRBS) excitation [2,12].
- The developed LFCUM structure includes only inertia and integrating links, which can be accurately identified by the proposed method.

There are several reasons to improve the LFCUM as developed in [3].

First, usage of this LFCUM requires identification of its parameters for every new operation point set, in vicinity of which this model is identified. Because this identification requires three experiments, the full model creation (for full load range) can be time- and cost consuming. So it is reasonable to develop LFCUM based on only one experiment. Such LFCUM is proposed in this paper by representing boiler pressure effects as a differentiating process.

Another problem relates to the identification method [3,8].

This method is successful if frequency response (FR) data is enough informative for the transfer function (TF) identification. Frequency interval $(\omega_{\min}, \omega_{\max})$ in which FR is identified depends on signal to noise ratio. So this interval can be reduced because of this ratio decreasing what will cause a loss of the identification accuracy. There are two ways to overcome this problem: either $\omega_{\min}$ decreasing without filtering the noised data or $\omega_{\max}$ increasing through this data filter. This paper modifies the method [3,8] in the frame of the second way.

Additional problem of the approach [3] may arise due to limited performances of an identification experiment. For example, a load set point change has a limited rate for a working unit. If FR will be identified using such test signal, the identified FR may be not enough informative to represent adequately a process in the high frequency domain. It means that the identified TF does not give the adequate representation of fast processes.

At the same time, net frequency abrupt deviation can lead to fast load changes. On the one hand, the above-identified TF can not adequately represent these load changes. On the other hand, the real load response caused by this abrupt deviation can be used for correction of the above identified TF. This paper presents a corresponding approach for this correction.

The behavior of LFCUM described here represents the basic dynamics of a 575MW unit at the Rutenberg Power Station (Israel).

2. MODEL DEVELOPMENT

2.1. Steam Generator Structure

For load-frequency control purposes, LFCUM is required to represent load and throttle pressure behavior. So, a model of boiler pressure effects has to be developed in the first instance.

The nonlinear equation [4] relates the steam flow S_F to the throttle pressures P_T and the control valve area C_V :

$$S_F = k \cdot C_V \cdot P_T \quad (1)$$

Expanding the right hand side (1) into the Taylor series around an operating point (C_{V0}, P_{T0}, S_{F0}) we derive the linear equation about deviations $(\Delta C_V, \Delta P_T, \Delta S_F)$:

$$\Delta S_F = k(\Delta C_V \cdot P_{T0} + \Delta P_T \cdot C_{V0}) \quad (2)$$

where $k = \dfrac{S_{F0}}{C_{V0} P_{T0}}$.

Assume that the boiler pressure effect model is described by the following equation in the Laplace transform form:

$$\Delta P_T(s) = W_{BL}(s) \cdot \Delta C_V(s) \quad (3)$$

We consider that (3) presents this effect for a throttle pressure process operating in a closed control loop. In this operation the throttle pressure set point is taken constant.

Substituting (3) into (2) and using the Laplace transform we arrive at the following incremental equation:

$$\Delta S_F(s) = (kP_{T0} + kC_{V0} W_{BL}(s))\Delta C_V(s) \quad (4)$$

As it follows from physical considerations, the transfer function $W_{BL}(s)$ possesses properties of a *differentiating* dynamic link. It is determined here as a link the transfer function of which has one zero in the origin of *s*-plane. This implies that a dynamic differentiating link can be represented as a series connection of a *pure* differentiating link with the transfer function *s* and a low-pass filter of arbitrary order.

$\Delta \hat{S}_F$ is estimated by the similar equation

$$\Delta \hat{S}_F(s) = (kP_{T0} + kC_{V0} \hat{W}_{BL}(s))\Delta C_V(s) \quad (5)$$

where $\hat{W}_{BL}(s)$ is conveniently called as a *boiler transfer function*. This transfer function has to be identified.

2.2. Turbine-Generator Structure

The turbine-generator model [4] is described in terms of deviations of the mechanical power ΔP_A and the steam flow $\Delta \hat{S}_F$ by the linear equation:

$$\Delta P_A(s) = W_{TG}(s) \cdot \Delta S_F(s) \quad (6)$$

$\Delta \hat{S}_F$ is estimated similarly:

$$\Delta \hat{P}_A(s) = \hat{W}_{TG}(s) \cdot \Delta \hat{S}_F(s) \quad (7)$$

where $\hat{W}_{TG}(s)$, a *turbine-generator transfer function,* has to be identified.

2.3. Load-Frequency Control System (LFC) Structure

For two identical 575MW units, No.1, 2 (Rutenberg PS) the LFC is presented by the following equations.

The governor as an electro-hydraulic servo is described by the saturation nonlinear function φ_1 relating the load-frequency controller output C_L and the feed-forward C_F from the network frequency deviations $\Delta F_N(t)$ to the control valve C_V position:

$$\Delta C_V = \varphi_1(C_L, C_F, HL, LL) \quad (8)$$

where *HL, LL* are high- and low- limits of C_V position.

The load controller with transfer function $W_L(s)$ forms the first component of control valves position demand C_L :

$$\Delta C_L(s) = W_L(s) \cdot \varepsilon_L(s) \quad (9)$$

The error load ε_L is calculated here as follows:

$$\varepsilon_L = \Delta L_{SP} - \Delta P_A + c \cdot J \cdot F_{N0} \cdot \frac{d\Delta F_N}{dt} + \varepsilon_F - k \cdot \Delta P_T \quad (10)$$

where: L_{SP} is load set point; P_A is actual electric power measured on the generator's terminals; J , c are the inertia constant of a power unit and a proportional gain, respectively; F_{N0} is an operating point of the Taylor series expansion for the net frequency function $F_N(t)$; *k* is a gain.

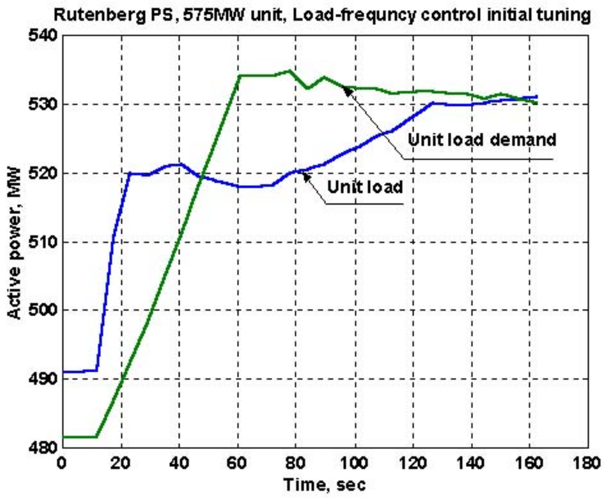

Fig.1. Unit 575MW responses with the tuned LFC. The unit load demand is equal to $L_{SP} + \varepsilon_F$

The component ε_F in (10) is formed as a non-linear function

$$\varepsilon_F = \varphi_2(D_R, \Delta F_N, RHL) \quad (11)$$

where *RHL* is the rate high limit of ε_F ; D_R is the *Droop coefficient* [MW/Hz].

The feed-forward C_F in (8) is described as a non-linearity

$$C_F = \varphi_3(D_R, \Delta F_N, FFHL, FFLL) \quad (12)$$

where *FFHL, FFLL* are high- and low- limits of C_F.

Fig.1 illustrates unit 575MW responses in the mode, which is equivalent to $\Delta F_N(t) = -0.18 \cdot 1(t), [Hz]$. As one can see, the unit load is increased on 30MW during 8sec when $RHL \approx 40 MW/min$. Such fast response is mainly caused by C_F. Both 575MW units are tuned identically.

2.4. Model Block Diagram

Fig.2 shows the block diagram of the developed model, which uses equations (4), (6), (8), (9). The functions (8), (11), (12) of LFC and hence the whole unit model are essentially non-linear.

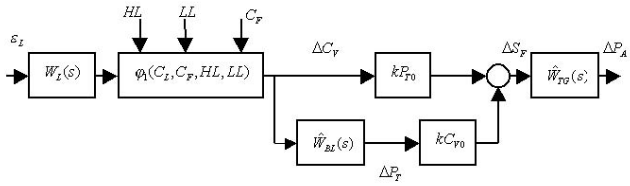

Fig.2. Block diagram of the linearized unit model

3. TURBINE-GENERATOR IDENTIFICATION

3.1. About Identification Method

The following two-stage procedure for the TFI process is used [3,8]: the first stage is FR identification of a process, while the second one is TF computation using the frequency response obtained from the first stage. The main reasons for that are as follows: the bandwidth in the frequency response identification is limited by $[0, \omega_{\max}]$ in order to represent more accurately the plant response itself (the response expected value). This is obtained by the indirect reduction of noise effects in test data [3]. This "filtered" FR makes it possible to lower the order of the corresponding transfer function calculated directly in the second stage.
There are several methods for TF computation (see reference in [3]) using the frequency response data. They are based on the least square method (LSM), so their convergence is problematic in the case of an unknown TF order. In [3,8] this problem is overcome in the following way.
Usually, transfer functions of power station processes are of the third order at the most. Because of this reason and assuming that the band $[0, \omega_{\max}]$ corresponds to the identified process, a few TF of the first, second and third orders (with and without zeros) are computed. Then we may expect the true TF falls between them.
The Control System Tuning Program (CSTP) [6,7] based on the method [3,8] is developed in the IEC.

3.2. Identification of the first- level TF

Only one identification experiment is needed to identify simultaneously transfer functions $\hat{W}_{TG}(s)$ and $\hat{W}_{BL}(s)$. This experiment is fulfilled in a power unit normal operation by changing the load set point ΔL_{SP} with its maximum rate. The identification data are the power unit time response

$$\{\Delta C_V(t), \Delta P_T(t), \Delta S_F(t), \Delta P_A(t)\} \qquad (13)$$

The turbine-generator transfer function $\hat{W}_{TG}(s)$ is calculated as the ratio $\hat{W}_{TG1}(s) = \Delta P_A(s) / \Delta S_F(s)$ using the method [3,8]. We called this function as *the first- level TF*.
If the load set point rate was not wide enough, the identified $\hat{W}_{TG1}(s)$ will adequately describe the turbine-generator dynamics only in a respectively low-frequency domain. In this case, the first-level TF has to be refined. The following theorem applied to this problem can be proved.

3.3. Theorem 1

Let the transfer function

$$\hat{W}_{TGk}(s) = \Delta P_A(s) / \Delta \hat{S}_{Fk}(s), \ k=1,2,3,... \qquad (14)$$

be the *k-level TF* where $\Delta \hat{S}_{Fk}(t)$ is the steam flow estimate after the power unit simulation with the *(k-1)- level TF* of this turbine-generator. We assume that $\Delta \hat{S}_{F1} \equiv \Delta S_F$.
Denote also the true transfer function of this turbine-generator as $W_{TG}(s)$.
Then

$$\lim_{k \to \infty} \hat{W}_{TGk}(s) = W_{TG}(s) \qquad (15)$$

4. BOILER IDENTIFICATION

The boiler transfer function $\hat{W}_{BL}(s)$ is calculated as the ratio $\hat{W}_{BL}(s) = \Delta P_T(s) / \Delta C_V(s)$ using the data (13). Recall that $\hat{W}_{BL}(s)$ is described as a differentiating link.
Let us assume that FR is identified in frequency interval $[\omega_{\min}, \omega_{\max}]$. Due to the dependence of $\omega_{\max}$ on the noise level, this interval can be reduced (see Theorem in [3]). Then FR is identified within a more narrow frequency interval, which can cause a decrease in the identification accuracy measured by [8]

$$R = M\{(m_h(t) - \hat{h}(t))^2\} \qquad (16)$$

where:
$M\{\bullet\}$ is the expected value of the bracketed function;
$m_h(t)$ is the expected value of the process output;
$\hat{h}(t)$ is the process model output.
There are two ways to provide the required accuracy: either $\omega_{\min}$ decreasing or $\omega_{\max}$ increasing. The theorem below applied to the second way can be proved.

4.1. Theorem 2

Let the initial data used for identification be the output *h(t)* and the input *u(t)* signals of the process. Suppose that $h(t) = m_h(t) + h^0(t)$, where $h^0(t)$ is an independent stationary random signal with zero mean value and spectral density function $H^o(i\omega)$; *u(t)* is a deterministic function. Further, $m_h(t) = u(t) = 0$ for $t \le 0$ and $m_h(t) = h_0$, $u(t) = u_0$ for $t \ge T$, where *T* is the recovery time of a time response.
Let the above initial data be filtered by the link $F(s) = (\sigma \cdot s + 1)^{-1}$. Then the new data are defined:

$$\begin{aligned} h_1(i\omega, \sigma) &= h(i\omega) F(i\omega) \\ u_1(i\omega, \sigma) &= u(i\omega) F(i\omega) \end{aligned} \qquad (17)$$

The following functions are introduced now:

$$\left.\begin{aligned} e_h(t) &= h_0 - h_1(t,\sigma) \\ e_u(t) &= u_0 - u_1(t,\sigma) \end{aligned}\right\} \qquad (18)$$

Let $m_h(t,\sigma) = h_0$ and $u_1(t) = u_0$ for $t \ge T$ where $m_h(t,\sigma)$ is the expected value of $h_1(t,\sigma)$.

In accordance with the Theorem [8], the frequency response of the process model $\hat{W}(i\omega)$ is calculated as the ratio

$$\hat{W}(i\omega) = e_h(i\omega)/e_u(i\omega) \qquad (19)$$

where $\omega \in [0, \omega_{\max}(\sigma)]$.

Then

$$\omega_{\max}(\sigma) > \omega_{\max}(0),\ \sigma > 0 \qquad (20)$$

Remark

One can assure that increasing $\omega_{\max}$ does not necessarily cause a rise of the identification accuracy measured by (16). So in parallel with $\omega_{\max}$ changing, values of $R(\omega_{\max})$ have to be checked.

5. IDENTIFICATION RESULTS

Two identical 575MW units, No.1, 2 (Rutenberg PS) were used in identification and validation experiments. The main goal was to check the accuracy of the unit's dynamic representation by the presented model on the vicinity of the boundaries around the steady-state mode. The CSTP [6,7] was used for all identification.

The steady-state operating point around which the unit No.1 was linearized is:

$$(P_{T0}, S_{F0}, P_{A0}, C_{V0}) = 174Atm, 1530t/h, 510MW, 80\% \quad (21)$$

The identification data (13) was obtained in response to the load set point ΔL_{SP} (Fig.4, a) of the unit No. 1.

5.1. Boiler identification of the power unit No.1

Three identified transfer functions of the unit No.1 boiler are given below together with filter parameters σ [*sec*], see Theorem 2:

$$\hat{W}_{BL}(s) = \frac{3740s^2 + 22s}{2657s^3 + 2458s^2 + 311s + 1}, \qquad \sigma = 1, \quad (23)$$

$$\hat{W}_{BL}(s) = \frac{-0.51s^2 + 20.3s}{223s^3 + 2322s^2 + 60s + 1}, \qquad \sigma = 100, \quad (24)$$

$$\hat{W}_{BL}(s) = \frac{-156s^2 + 20s}{0.96s^3 + 23s^2 + 44.8s + 1}, \qquad \sigma = 120 \quad (25)$$

Identification results involve also a comparison between time responses of processes and their identified models (Fig.3). As one can see from these figures, the best boiler model is described by (24) and the optimal filter is defined by $\sigma = 100\sec$. We emphasize that a change of σ from 100sec to 120sec totally change the character of the results (compare Fig3b,c). This phenomenon is explained as follows:

According to Theorem 2 the following conditions have to be fulfilled: $m_h(t,\sigma) = h_0$ and $u_1(t) = u_0$ for $t \ge T$. Because the data length are bounded by T (*T=370sec*, Fig.3), there exists a certain σ (namely $\sigma > 100\sec$) which causes violating these conditions and deteriorating identification results.

We note that (24) can be represented as a series connection of the differentiating link *20.3s* and the filter $(-0.028s + 1)/(223s^3 + 2322s^2 + 60s + 1)$.

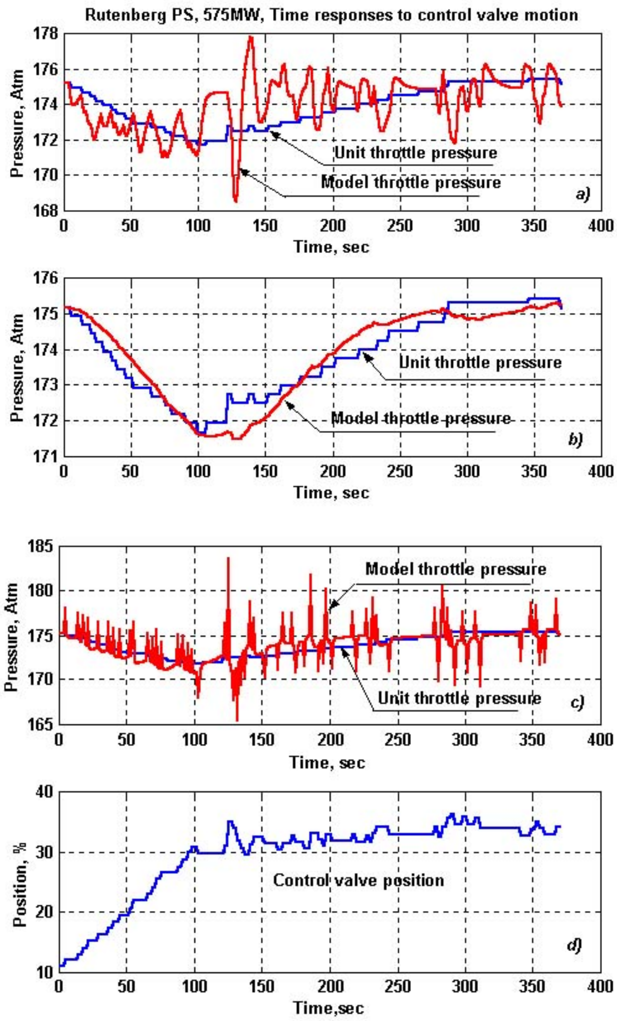

Fig.3. Plot of simulated and measured throttle pressure responses: a) $\sigma = 1\sec$; b) $\sigma = 100\sec$; c) $\sigma = 120\sec$

5.2. Turbine-generator identification

The first-level TF of the turbine-generator of the power unit No.1 identified by using CSTP is as follows:

$$\hat{W}_{TG1}(s) = \frac{0.32}{24.1s + 1} \qquad (26)$$

The steam flow estimate satisfies the linear equation (2) around the operating point (21):

$$\Delta\hat{S}_F = 5.3\Delta\hat{C}_V + 2.4\Delta\hat{P}_T \qquad (27)$$

By usage of (24), (26), (27) time responses of the closed LFCUM to the load set point ΔL_{SP} (Fig.4, a) were simulated (Fig.4). As one can see, there is a sufficiently good match between the model responses and real responses of unit No.1.

In this identification experiment, the load up extends over 300sec. At the same time, abrupt net frequency deviations cause faster responses of duration 10-20sec. So, the model (26) can not adequately describe the load process in the high frequency domain and it has to be corrected.

The 2nd- and 3rd-level models for turbine-generator of unit No.1 are identified following Theorem 1. The data

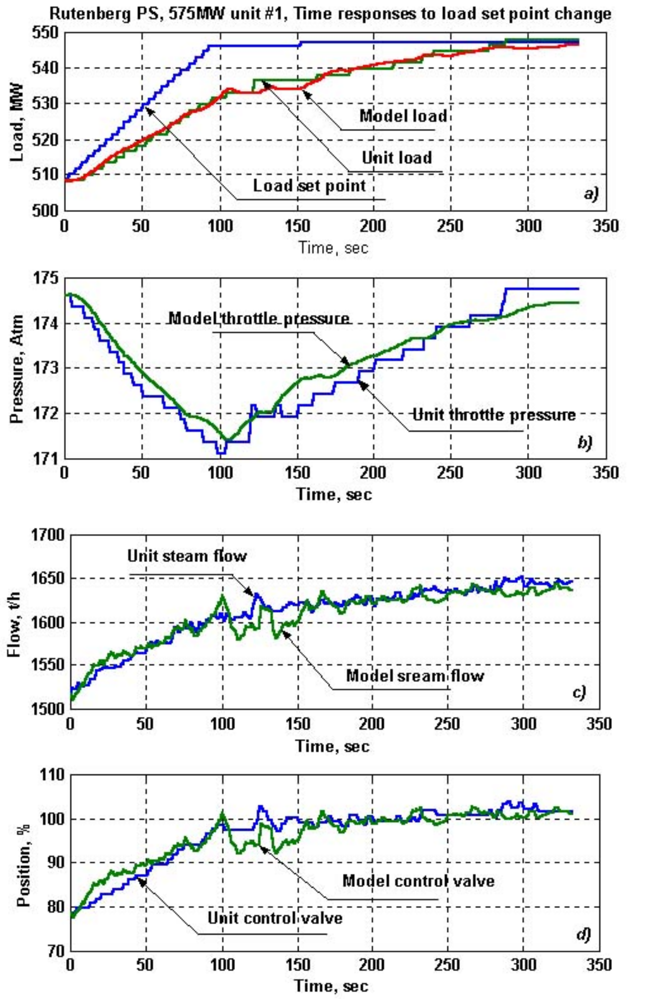

Fig.4. Plot of simulated and measured responses to the load set point ΔL_{SP} *(a): b)* $\Delta P_T(t)$ *; c)* $\Delta S_F(t)$ *; d)* $\Delta C_V(t)$

$\{\Delta S_F(t), \Delta P_A(t)\}$ are acquired from an interruption caused by 218MW unit at Eshkol PS tripping.

The following transfer functions are identified:

$$\hat{W}_{TG2}(s) = \frac{0.46}{5.32s + 1} \qquad (28)$$

$$\hat{W}_{TG3}(s) = \frac{0.37}{8.1s^2 + 4.7s + 1} \qquad (29)$$

The transfer function $\hat{W}_{TG1}(s)$ identified by the "slow data" (13) can not accurately reproduce the fast components of this unit response. Usage of $\hat{W}_{TG3}(s)$ increases the prediction accuracy (see validation results below).

6. VALIDATION RESULTS

The identified model was validated by simulation of units No.1-2 at Rutenberg PS behavior in regimes of net frequency abrupt deviations. This validation is fulfilled by usage of the third-level model for turbine-generator. The functions (24),

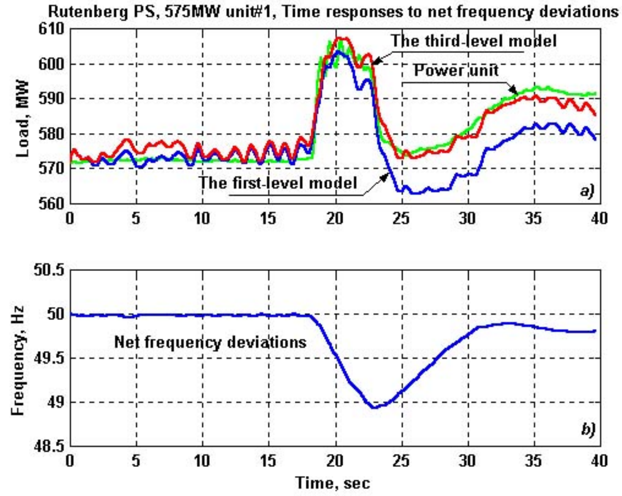

Fig.5. Plot of simulated and measured responses of 575MW unit No. 1 to net frequency abrupt deviations

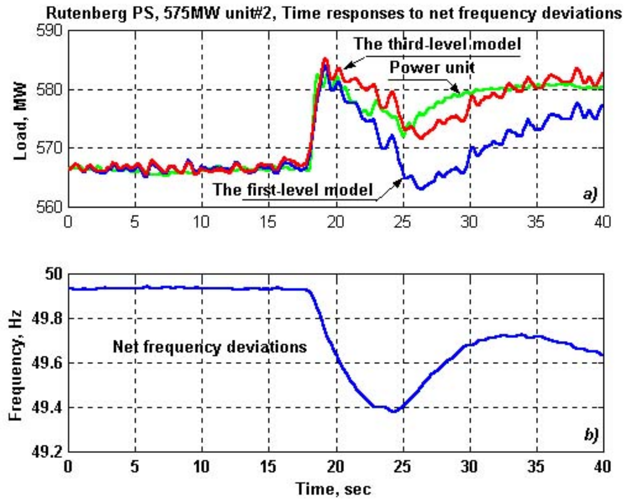

Fig.6. Plot of simulated and measured responses of 575MW unit No.2 to net frequency abrupt deviations

(27), (29) were used without changes in validation tests. Two of them are exemplified in Fig.5, 6.

The time responses (Fig.5) show the behavior of units No.1 to a grid frequency drop (Fig5b) caused by 575MW unit at Maor David PS tripping. Fig.6 illustrates the behavior of units No.2 to a grid frequency deviations (Fig6b) caused by 218MW unit at Eshkol PS tripping.

As one can see from Fig.5, 6 the identified model represents dynamic response of Rutenberg PS units No.1, 2 with sufficient accuracy.

7. CONCLUSIONS

The simplified generating unit model oriented towards load-frequency control and a method for its identification are presented.
The purpose of this model development is to obtain the best possible accuracy of unit load and of throttle pressure simulation which are the most important variables for the analysis of the behavior of the load frequency control system. In the general case, the developed model requires only one identification experiment, which is achieved through representing boiler pressure effects as a differentiating process. The identified model can be corrected by the developed procedure using data of unit behavior in normal working regimes. The presented modification of the identification method extends transfer function bandwidth. In addition, noise effects are also reduced.
The developed model can be used for redesign or tuning of load-frequency control system, for AGC control purposes as well as building or setting up a real-time simulator for dispatcher training. The modeling for 575MW power units of the IEC is fulfilled by implementation of the proposed model and its identification approach yielding sufficiently accurate results.

8. ACKNOWLEDGMENT

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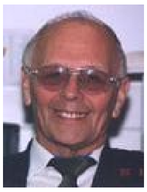
10. BIOGRAPHIES

Steve Glickman was born in the United States in 1947. He received his BsC in chemistry, math & physics from Stevens Institute of Technology in New Jersey. He worked for Leeds & Northrup in Pennsylvania (a major manufacturer of industrial control and computer systems) for 16 years where he was a field systems startup engineer, field project manager, as well as a systems programmer. In 1985, he immigrated to Israel and began working for the Israel Electric Corporation at the Rutenberg Power Station where he worked for 17 years. He was directly involved in the startup of the station's four generating units (total capacity - 2250 MW). At Rutenberg, he worked as the manager of the controls department, and after this as the plant manager. He is presently the assistant to the manager of the IEC Generating Division in charge of electrical matters, controls and computerization.



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