Optimal Incentive Design for Targeted Penetration of Renewable Energy Sources

Indrajit Das, Student Member, IEEE, Kankar Bhattacharya, Senior Member, IEEE, and Claudio Cañizares, Fellow, IEEE

Abstract—Environmental concerns arising from fossil-fuel based generation has propelled the integration of less polluting energy sources in the generation portfolio, and simultaneously, has motivated increased energy conservation programmes. In today’s deregulated electricity market, most participants (e.g., GENCOs, local distribution companies or LDCs) focus on maximizing their profits, and thus they need to be incentivized to invest in renewable generation and energy conservation, which are otherwise not profitable ventures. Therefore, this paper proposes a novel holistic generation expansion plan (GEP) model that enables the central planning authority to design optimal incentive rates for renewable integration and energy conservation targets, considering the investor interests and constraints. The model also determines the siting, sizing, timing, and technology required to adequately supply the projected demand over the planning horizon. The model is applied to the generation planning of Ontario, Canada, based on realistic data, to determine appropriate incentives for investors in renewable generation and energy conservation by LDCs. The obtained optimal incentives are shown to be similar to the ones currently in place in Ontario, with a slightly shorter pay-back period for investors. The effect of uncertainties associated with solar and wind energy availability, on the GEP model is also examined using Monte Carlo simulations.

Index Terms—Optimal incentives, optimal generation expansion planning, energy conservation, renewable energy integration.

I. GLOSSARY AND NOMENCLATURE

Abbreviations

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<tr>
<th>Abbreviation</th>
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<tbody>
<tr>
<td>BAU</td>
<td>Business-as-Usual</td>
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<tr>
<td>BIO</td>
<td>Bio-based power generation</td>
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<td>COAL</td>
<td>Coal-based power generation</td>
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<tr>
<td>CPA</td>
<td>Central Planning Authority</td>
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<td>DSM</td>
<td>Demand Side Management</td>
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<td>FIT</td>
<td>Feed-in-Tariff</td>
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<td>GAS</td>
<td>Gas-based power generation</td>
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<td>GENCO</td>
<td>Generation Company</td>
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<td>GEP</td>
<td>Generation Expansion Planning</td>
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<td>GPV</td>
<td>Ground-mounted PV based power generation</td>
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<td>GRM</td>
<td>Generation Reserve Margin</td>
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<td>HNR</td>
<td>Market-price-based hydro power generation</td>
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<tr>
<td>HOEP</td>
<td>Hourly Ontario Energy Price</td>
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<td>HR</td>
<td>Regulated-price-based hydro power generation</td>
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Parameters

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<th>Parameter</th>
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<tr>
<td>$a_0$</td>
<td>Incentive rate for energy conservation [$/MWh]</td>
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<tr>
<td>$a_b$</td>
<td>Incentive rate for demand reduction [$/MW]</td>
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<td>$b_0$</td>
<td>Generation reserve margin (GRM) [%]</td>
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<tr>
<td>$B_{k,i,j}$</td>
<td>B-matrix data of zonal transmission system [p.u.]</td>
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Introduction

The traditional paradigms and philosophies of power system planning have undergone significant changes since deregulation of the power industry and with government policies on emission reductions. Thus, the need for less polluting renewable energy sources (RES) in generation expansion plans (GEP) has been widely recognized. However, with the proliferation of independent power producers and GENCOs in electricity markets, which are profit maximization oriented, integration of relatively more expensive RES has needed incentive mechanisms for its realization. Local distribution companies (LDCs), on the other hand, are more interested in selling electricity rather than reducing the demand; thus, the adoption of energy conservation measures by LDCs, which is an integral part of “cleaning” the electricity grid, are also only plausible when suitable incentives are in place.

Modifications and improvements to the traditional GEP model and various associated solution methodologies have been reported in [1]. In [2], the effect of optimal spot pricing on GEP is examined, and socially optimal investment conditions are derived and integrated into the GEP. The authors in [3] examine generation investment decisions under time-of-use electricity rates considering social welfare maximization. However, with restructuring of the power industry and the associated presence of GENCOs, a deviation from the least-cost philosophy toward an investor driven GEP has taken place [4], and consequently, investment decisions which may be non-optimal from the planner’s point of view, need to be considered now. A multi-period, multi-objective, GEP model that minimizes system cost, and environmental impact, and incorporates risk of fuel price fluctuations is proposed in [5], which is solved using multi-criteria programming and analytical hierarchy processes. A security constrained multi-GENCO GEP model is presented in [6], which considers locational marginal prices, transmission security, and a capacity payment from the regulator as an incentive to GENCOs for adding new units.

The research literature has addressed improvements to the GEP problem extensively, as discussed in [7], proposing multi-level, multi-criteria models to consider the conflicting objectives of investor profit maximization and the planner’s system cost minimization, including RES and associated uncertainties. In particular, the impact of RES and their uncertainty on GEP has been widely studied. Thus, for example, reference [8] presents a planning-cum-production simulation model that determines the optimal generation mix including distributed resources, transmission upgrades, and investments in demand side management (DSM), while evaluating all central and local investments simultaneously. In [9], RES are considered in the planning process within the energy growth forecast models, viewing them as negative loads. A new dimension of generation flexibility is introduced into GEP in [10], where the fixed and variable costs of generation are considered to be uncertain. The need for explicitly evaluating generation flexibility, vis-à-vis the variability of net load, wind forecast, and uncertainties of system component outages are presented in [11] and [12]; increased penetration of intermittent renewable generation renders the operational flexibility of the generation portfolio strategically important, and has a direct impact on the system operating costs. An offline flexibility index is proposed in [13] to evaluate the variability of wind generation and examine its effect on GEP and market operation.

Variables

\(Cap_{Ex,k,i}\) Existing capacities over the plan horizon [MW]
\(CC_{Ex,k}\) Capital cost [$/kW]
\(CF_{Ex,k}\) Capacity factor [%]
\(Cap_{Min}\) Minimum capacity factor for existing sources [%]
\(\Delta t_b\) Time duration of load blocks [hours]
\(ED_{k,b}\) Energy demand [MWh]
\(Em_s\) Emission rate [kg of eqCO2/MWh]
\(g_s\) Gestation period [years]
\(LF\) Transmission loss factor [%]
\(N_1\) Period of new installations [years]
\(N\) Plan horizon [years]
\(OMF_{Ex,k}\) Fixed O&M cost [$/kW]
\(OMV_{Ex,k}\) Variable O&M cost [$/MWh]
\(PD_{Ex,k}\) Annual zonal peak demand [MW]
\(PT_{Max,k,i,j}\) Maximum power transfer between zones [MW]
\(Q_s\) Number of binary variables for technologies
\(Z\) Number of transmission zones
\(\alpha\) Discount rate [%]
\(\beta_{Ex,k}\) Fuel prices [$/MWh]
\(\mu_{Ex,k,b}\) Average annual electricity market price [$/MWh]
\(\nu_{Ex,k,b}\) Regulated price [$/MWh]
\(\phi_{Max,k}\) Maximum payback period limit [years]
\(\rho_{Ex,k,i}\) Incentive rates for existing capacities [$/MWh]
\(\psi_{Max,k}\) Minimum power generation at all time [%]
\(\theta\) Capital recovery factor
\(\zeta\) Emission penalty [$ / ton of eqCO2 ]
\(\theta_s\) Unit size of new capacity additions [MW]
\(\sigma\) Target penetration level of \(\delta\) technologies [%]
\(\Gamma_{s,i}\) Zonal capacity addition potentials [MW]
\(T_{E,k}\) Annual energy generation potentials [MWh]

\(\Omega\) NPV of total costs and payments [$]

II. Introduction

The traditional paradigms and philosophies of power system planning have undergone significant changes since deregulation of the power industry and with government policies on emission reductions. Thus, the need for less polluting renewable energy sources (RES) in generation expansion plans (GEP) has been widely recognized.
Very little work is reported on the design of optimal incentives to attract investments in RES. Reference [14] presents a bilevel optimization approach that designs efficient incentive policies to encourage investments in RES, while achieving the target RES penetration levels. In [15], the impact of incentive schemes (e.g., feed-in-tariffs or FIT, RES quota, emission trade, carbon tax) and emission on GEP is studied from a GENCO’s perspective. The uncertainty associated with RES is taken care of by a suitable capacity factor, and it is argued that there is a need for proper incentive mechanisms to render RES economically viable.

The traditional power system planning problem considers demand side activities as external factors, and renewable generation is incorporated at the operational stage. In order to achieve both objectives of incentive design for RES integration and energy conservation, the classical Integrated Resource Planning (IRP) philosophy needs to be revisited. IRP takes into account the supply-side and demand-side resources as a whole and uses them in an efficient, economic, and rational way, so as to reduce the investments in new capacity installations and operating expenses while providing adequate energy supply at lowest cost. The resource choices for IRP are conventional and RES, owned by either large utilities or independent power producers; improvements in the transmission and distribution systems; and DSM [16]. The revenue loss of the utilities due to reduced demand, and their failure to consider environmental and social factors are some of the barriers of IRP. Thus, it is suggested in [17] that proper financial incentives to LDCs could improve the delivery of DSM services, and environmental and social factors need be incorporated in the IRP. A multi-objective framework, using compromise programming, to simultaneously integrate various DSM options in electric utilities’ IRP is presented in [18]; the DSM options are characterized as supply side resources, and their interaction amongst themselves, along with their simultaneous vis-à-vis sequential integration in the IRP, is examined. Finally, the restructuring of the electricity industry and the resulting competitive environment impact in the classical IRP strategy is considered in [19], where the maximization of investment profitability instead of cost minimization is used to determine optimal capacity additions.

From the above discussions, it is clear that a holistic GEP model, based on the IRP philosophy, is needed. Such a model should not only be able to provide the traditional optimal solution to GEP problems, but should also be designed to determine the optimal incentives for both RES integration and energy conservation. Therefore, a model that considers the perspective of the central planning authority (CPA) and includes all the economic transactions with GENCOs and LDCs is proposed in this paper, to determine the optimal incentives for the integration of RES, while accounting for the investor interests. The proposed GEP mathematical model not only replicates a CPA by considering all capital, and operation and maintenance (O&M) costs of new and existing generation plants, but also considers the incentives and other market price based payments made to investors. In addition, the proposed GEP model also considers the incentive payments made by CPA to LDCs to encourage energy conservation and demand reduction. Furthermore, emissions from generation plants are considered within the GEP model via environmental penalty costs, which can be seen as an indirect incentive. Thus the overall objective of the proposed holistic GEP is to seek a minimum overall cost considering all the above components, i.e., capital, O&M, incentive payments and environmental penalties. The solution to the proposed model provides the optimal incentives that encourage integration of RES while achieving targeted levels of RES penetration and demand reduction, and determining the optimal site, size, time, and technology of new generation capacity additions. The main contributions of this work can be summarized as follows:

- The proposed GEP framework can be used to determine the optimal incentive rates for RES integration and energy conservation, through a technique that has not been presented so far.
- The holistic GEP model amalgamates, for the first time, cost minimization of GENCOs with the minimization of CPA’s payments to GENCOs and LDCs, while also considering cost of emissions. This ensures that the designed incentives are optimal, considering both GENCOs’ profit and the system costs.
- The proposed holistic GEP optimally determines the sizing, siting, and timing of new capacity additions, simultaneously with the optimal RES incentives, considering both RES penetration and energy conservation targets.

The rest of this paper is organized as follows: Section III presents the comprehensive details of the proposed holistic GEP model. Section IV describes the details of the test case corresponding to the province of Ontario, Canada, presenting as well the GEP results for the province, and comparing the obtained incentives with those currently being used; uncertainties embedded in solar and wind capacity factors are also studied based on Monte Carlo simulations. Finally, Section V highlights the conclusions and main contributions of this work.

III. THE PROPOSED HOLISTIC GEP MODEL

A. Model Assumptions

The framework of the proposed holistic GEP model is shown in Fig. 1, where the main inputs and outputs of the model are highlighted. The assumptions made to develop the proposed model are the following:

- The system is modelled using several transmission corridors, load variations in different locations, and regional availabilities of solar, wind, and/or hydro generation.
A DC load flow model is used to determine the power flows between zones and thus account for the main transmission system constraints and bottlenecks.

A typical pre-specified loss factor for the transmission system is considered as in other planning studies [8], [20].

The main input parameters that must be defined and are independent of the grid under study are: the discount rate \( \alpha \); cost of emission per unit energy \( \xi \); generation reserve margin \( b_0 \); gestation period \( g_\text{p} \); installation plan period \( N_\text{p} \); minimum capacity factor for dispatchable sources \( CF_{\text{Min}} \); RES incentive rates limits \( \rho_{\text{Max}} \) and \( \rho_{\text{Min}} \); payback-period limits \( \phi_{\text{Max}} \) and \( \phi_{\text{Min}} \); and unit size of installation for new capacity additions \( \theta_\text{s} \).

**B. Planning Objective**

The objective of the GEP model (\( \Omega \)) is to minimize the total system cost and incentive payments from the perspective of the CPA, as discussed earlier, and is given by:

\[
\Omega = \sum_{s} \sum_{k=1}^{N} \sum_{i=1}^{Z} R_{x,k,i} + C_{x,k,i} + EC_{x,k,i} \tag{1}
\]

where all variables and parameters are defined in Section I. Here, \( R \) is the total payment made by the CPA to GENCOs (which in effect is their revenue), and is divided into two categories, namely, existing and new, as follows:

\[
R_{x,k,i} = R_{x,k,i}^{\text{Ex}} + R_{x,k,i}^{\text{New}} \tag{2}
\]

These payments may be based on the market price (\( \mu \)) or regulated price (\( \nu \)) or incentives (\( \rho \)), and are computed as:

\[
R_{x,k,i}^{\text{Ex}} = \sum_{b=1}^{3} \mu_{b,k} E_{x,k,i,b} \tag{3}
\]

\[
R_{x,k,i}^{\text{New}} = \sum_{b=1}^{3} \nu_{x,b,k} E_{x,k,i,b} + \sum_{b=1}^{3} \rho_{x,b,k} E_{x,k,i,b} \tag{4}
\]

where \( s1 \cup s2 \cup s3 = s \), and the energy can be written as:

\[
E_{x,k,i,b} = E_{x,k,i,b}^{\text{Ex}} + E_{x,k,i,b}^{\text{New}}. \tag{5}
\]

The decision variables \( \rho_{x,s,k,i} \) in (4) are the zonal incentive rates for the corresponding technologies, which are determined from the model solution.

The total cost of generation in (1), given by \( C \), is the sum of the costs pertaining to installation (\( CI \)), fuel (\( CFL \)), and O&M (\( COM \)) of new and existing facilities:

\[
C_{x,k,i} = CI_{x,k,i} + CFL_{x,k,i}^{\text{New}} + CFL_{x,k,i}^{\text{Ex}} + COM_{x,k,i} + COM_{x,k,i}^{\text{New}} \tag{6}
\]

where \( CI \) for all generation technologies is computed using:

\[
CI_{x,k,i} = NC_{x,k,i} CC_{x,k,i}. \tag{7}
\]

The CFL of existing and new facilities are dependent on respective fuel prices (\( \beta \)), and is given by:

\[
CFL_{x,k,i}^{\text{Ex}} + CFL_{x,k,i}^{\text{New}} = \beta_{x,k} \left( \sum_{b=1}^{3} E_{x,k,i,b}^{\text{Ex}} + \sum_{b=1}^{3} E_{x,k,i,b}^{\text{New}} \right) \tag{8}
\]

and the \( COM \) for existing and new technologies is given by:

\[
COM_{x,k,i} + COM_{x,k,i}^{\text{New}} = OM_{x,k} (Cap_{x,k,i}^{\text{Ex}} + Cap_{x,k,i}^{\text{New}}) + OMV_{x,k} \left( \sum_{b=1}^{3} E_{x,k,i,b}^{\text{Ex}} + \sum_{b=1}^{3} E_{x,k,i,b}^{\text{New}} \right) \tag{9}
\]

where the generation capacities are obtained as follows:

\[
Cap_{x,k,i} = Cap_{x,k,i}^{\text{Ex}} + Cap_{x,k,i}^{\text{New}}. \tag{10}
\]

The emission cost in (1), given by \( EC \), is obtained as:

\[
EC_{x,k,i} = \xi Em \sum_{b=1}^{3} E_{x,k,i,b} \tag{11}
\]

where \( Em \) is the equivalent CO\(_2\) emission (eqCO\(_2\)) per unit energy generation from various technologies, and \( \xi \) is the penalty (cost) per unit emission.

The incentive payments (\( ECP \)) on energy conservation (\( CN \)) and demand reduction (\( DR \)), given in (11), are calculated as:

\[
ECP_{x,k,i} = a_0 \sum_{b=1}^{3} CN_{x,k,i,b} + a_1 DR_{x,k,i,b} \tag{12}
\]

where \( DR \) is related to \( CN \) as follows:

\[
CN_{x,k,i,b} = DR_{x,k,i,b} \Delta t_b \tag{13}
\]

assuming that \( a_0 = 0, a_1 \Delta t_b \), since this ensures equal weight for \( CN \) and \( DR \) in \( ECP \), thus equating their corresponding incentive payments. The incentive rates for energy conservation (\( a_0 \)) and demand reduction (\( a_1 \)) are adjustable parameters which need to be tuned optimally to achieve targeted energy conservation levels, as explained in Section IV-A1.
C. Model Constraints

1) Energy Balance: This constraint ensures zonal energy demand-supply balance and also takes into account the energy transfer between transmission zones, as follows:

\[ \sum_{s} E_{s,k,i,b} - \sum_{j=1}^{Z} ET_{k,i,j,b} + \sum_{j=1}^{Z} ET_{k,j,i,b}(1 - LF) = \left( ED_{k,i,b} - \sum_{s} E_{s,k,i,b} \right) - CN_{k,i,b} \] (14)

where \( s \cup s = s \), and \( ET \), a positive decision variable, is related to bus voltage angles by the following dc power flow equations:

\[ ET_{k,i,j,b} = B_{k,i,j}(\delta_{k,i,b} - \delta_{k,j,b})\Delta I_{b}. \] (15)

2) Power Transfer and Bus Angle Limits: The following limits ensure the operational security of the transmission system:

\[ ET_{k,i,j,b} \leq PT_{k,i,j}^{Max} \Delta I_{b} \] (16)

\[ \delta_{Min} \leq \delta_{k,i,j,b} \leq \delta_{Max}. \] (17)

3) Adequacy Constraint: The following constraint ensures that the proposed GEP considers the system reliability by ensuring that a specified generation reserve margin (GRM), as defined in [21], is maintained in the system, while taking into account the peak demand reduction resulting from energy conservation measures:

\[ \sum_{s} \sum_{j=1}^{Z} Cap_{s,k,i} \geq (1 + b_{0}) \sum_{i=1}^{Z} PD_{i,k} - \sum_{i=1}^{Z} DR_{i,k}, - s \] (18)

where \( b_{0} \) (GRM) is a given percentage of peak demand.

4) Dynamic Constraint on Capacity Addition: This is incorporated as follows:

\[ Cap_{s,k+1,i}^{New} = NC_{s,k,i} + Cap_{s,k,i}^{New} \] (19)

where the timing for new installations are bounded by \( g_{s} \) and \( N_{1} \) as follows:

\[ NC_{s,k,i} = 0 \]

\[ \forall \_ k = 1, \ldots, g_{s}, (N_{1} + 1), \ldots, N \quad \text{and} \quad N_{1} > g_{s}. \] (20)

Here, it is assumed that, if a given capacity is commissioned in year \( k \), the total investment and installation takes place in year \( k-1 \), instead of those being distributed over the typical gestation period \( g_{s} \). Since commissioning takes \( g_{s} \) years from the initiation of the plan, (20) is used to defer the commissioning by a minimum of \( g_{s} \) years; and \( N_{1} \) is assumed as the year in the planning horizon after which there is no new installations, as shown in Fig. 2.

5) Energy Dispatchability Constraint: The annual maximum energy generation capability of dispatchable sources is given by:

\[ \sum_{b=1}^{3} E_{s6,k,i,b} \leq 8760 \times CF_{s6} Cap_{s6,k,i} \] (21)

while for non-dispatchable sources, the annual energy generation should satisfy the following:

\[ \sum_{b=1}^{3} E_{s7,k,i,b} = 8760 \times CF_{s7} Cap_{s7,k,i} \] (22)

where \( s6 \cup s7 = s \). Note that (21) is an inequality constraint since the dispatchable resources have the flexibility to adjust their generation, whereas non-dispatchable sources in (22) will generate as per their assumed annual capacity factor.

6) Power and Minimum Energy Generation Limits: The following minimum energy constraint is imposed on existing dispatchable capacities, so that the new plan does not shut them down before their usual end of life, in favour of less costly alternatives:

\[ \sum_{i=1}^{3} E_{s6,k,i,b} \geq 8760 \times CF_{s6}^{Min} Cap_{s6,k,i}^{Ex}. \] (23)

And the power generated at different time blocks is limited by the available capacity as follows:

\[ E_{s,k,i,b}\Delta t_{b} \leq Cap_{s,k,i} \] (24)

In addition, the price regulated capacities have a minimum power generation limit (\( \psi \)) at base load, given by:

\[ E_{s2,k,i,b}\Delta t_{b} \geq \psi_{s2} Cap_{s2,k,i}. \] (25)

7) Discounted Pay-Back-Period (PBP) Constraint [22]: The following constraint ensures that the PBP is bounded by specified periods, with a lower limit imposed so that the incentives are not too high:

\[ \phi_{s3,i}^{Min} \leq \phi_{s3,i} \leq \phi_{s3,i}^{Max}. \] (26)

Here, \( \phi \) is computed using the following non-linear equation:

\[ \phi_{s3,i} = \frac{\sum_{k=1}^{N} CF_{s3,i,k} (1 + \alpha)^{k}}{\sum_{k=1}^{N} CF_{s3,i,k} (1 + \alpha)^{k} - \sum_{k=1}^{N} (COM_{s3,i,k}^{New} + CFL_{s3,i,k}^{New})} \theta \] (27)

where the numerator is the Net Present Value (NPV) of installation costs [22], and the denominator is the levelized cash flow, distributed evenly over the planning horizon \( N \) of the NPV of cash flow (term inside bracket), using a capital recovery factor \( \theta \).

8) Integer Constraint: Binary variables are used to obtain integer solutions for the new capacity additions as follows:

\[ NC_{s,k,i} = \sum_{q=1}^{Q} \theta_{s} W_{s,k,i,q} \] (28)

where \( \theta_{s} \) is the unit size of installation for new capacity additions and \( W \) is a binary variable.
Fig. 3. Inputs and output variables and equations of the proposed GEP model.

9) **RES Penetration Target:** This is achieved as follows:

\[ \sum_{i=1}^{Z} \sum_{b=1}^{3} E_{s,k,i,b} \leq T_{s,k} \]  

(30)

where \( \sigma \) is the targeted penetration level in %. If the target applies to incentive based technologies only, then \( s8 \) will be replaced by \( s3 \) and \( \sigma \) by \( \sigma^{s3} \).

10) **Energy and Power Potentials:** Annual energy generation potential or zonal new capacity addition potential, as applicable, are given by:

\[ \sum_{i=1}^{Z} \sum_{b=1}^{3} E_{s,k,i,b} \leq T_{s,k} \]  

(30)

\[ \sum_{k=1}^{N} NC_{s,k,j} \leq \Gamma_{s,j} \]  

(31)

Equations (1) to (29) describe the nonlinear mathematical optimization model of the holistic GEP, with nonlinearities in (4) and (27). The constraints in (30) and (31) are included in the optimization model only when applicable.

D. **Linearization Process**

The linearization technique described in [23] is applied to the proposed holistic GEP model, which is a Mixed Integer Non-Linear Programming (MINLP) planning problem, to simplify it into a Mixed Integer Linear Programming (MILP) problem and thus allow for simpler and well-tested solution approaches.

1) **Optimal RES Incentives:** The nonlinear part of (4) can be rewritten as:

\[ R_{s,k,j,i}^{New} = \rho_{s,k,j}^{New} \sum_{b=1}^{3} E_{s,k,i,b}^{New} \]  

(32)

and to remove the nonlinearity, the approach described in [23] yields:

\[ R_{s,k,j}^{New} \leq \rho_{Max}^{New} \sum_{b=1}^{3} E_{s,k,i,b}^{New} \]  

(33)

\[ R_{s,k,j}^{New} \geq \rho_{Min}^{New} \sum_{b=1}^{3} E_{s,k,i,b}^{New} \]  

(34)

Hence, (4) is replaced by the following:

\[ R_{s,k,j}^{New} + R_{s,k,j}^{New} = \sum_{b=1}^{3} \mu_{k,b} E_{s,k,i,b}^{New} + \sum_{b=1}^{3} \nu_{s,k,b} E_{s,k,i,b}^{New} \]  

(35)

together with (33) and (34), thus removing the nonlinearity.

The zonal values of \( \rho_{s,k,j}^{New} \) for the incentive-driven sources can later be calculated from the model solution using:

\[ \rho_{s,k,j}^{New} = \frac{\sum_{k=1}^{N} R_{s,k,j}^{New}}{\sum_{k=1}^{N} \sum_{b=1}^{3} E_{s,k,i,b}^{New}} \]  

(36)

and the province-wide values of \( \rho_{s,k,j}^{New} \) can later be computed as follows:

\[ \rho_{s,k,j}^{New} = \frac{\sum_{k=1}^{N} Z_{s,k,j}^{New}}{\sum_{k=1}^{N} \sum_{b=1}^{3} E_{s,k,i,b}^{New}} \]  

(37)

2) **PBP:** This is linearized by replacing (26) and (27) with:

\[ \sum_{k=1}^{N} CI_{s,k,i} \leq \phi_{Max} \left( \sum_{k=1}^{N} R_{s,k,j}^{New} - \left( COM^{New}_{s,k,j} + CFL^{New}_{s,k,j} \right) \right) \]  

(38)

\[ \sum_{k=1}^{N} CI_{s,k,i} \geq \phi_{Min} \left( \sum_{k=1}^{N} R_{s,k,j}^{New} - \left( COM^{New}_{s,k,j} + CFL^{New}_{s,k,j} \right) \right) \]  

(39)

Then, \( \phi \) can later be computed from the optimization solution using (27).

The linearized holistic GEP model in MILP form thus comprises equations (1) to (3), (5) to (25), (28), (29), (30) to (35), (38) and (39), with (30) and (31) being included when applicable, as shown in Fig. 3.

IV. **The Case of Ontario, Canada**

The holistic GEP model is implemented for the province of Ontario, Canada, with a plan horizon of 25 years (2011 to 2035). A simplified ten-zone transmission system model for Ontario is used, as shown in Fig. 4 [24], where the relevant transmission data \( (B_{s,k,i}, P_{s,k,i}^{Max}) \) is taken from [25], along with an assumed transmission loss factor \( (LF) \) of 5%.

The set of market price based technologies \( (s8) \) are COAL, GAS, OIL, and some hydro generations (HNR). Similarly, some hydro and nuclear generators receiving regulated prices (HR and NR, respectively) and nuclear generator with contracted prices (NCP) are categorized in the set \( s2 \). The incentive-driven technologies \( (s3) \) are biomass (BIO), ground-mounted PV (GPV), rooftop PV (RPV), wind onshore (WON) and wind offshore (WOF) generation. Furthermore, only RPV is considered to be a distribution connected resource \( (s4) \), and all types of wind and solar generation are considered non-dispatchable \( (s6) \). The existing generation capacities are shown in Fig. 5 [26], [27], which depicts the shutdown of coal based plants in 2014, as decided by Ontario power authority (OPA) to reduce emissions. The end-of-life shutdown of one NR generation facility in 2020 is also shown (Pickering, in TORONTO...
Fig. 4. Ontario transmission zones [24].

Fig. 5. Existing capacities over the plan horizon [26], [27].

### TABLE I

**Capital and O&M Costs of Gen. Technologies and CO₂ Emission [28]**

<table>
<thead>
<tr>
<th>i</th>
<th>CC, [$/kW]</th>
<th>CD, [%]</th>
<th>O&amp;M, [$/kW]</th>
<th>OMV, [$/MWh]</th>
<th>Em, [Kg of eqCO₂ per MWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>BIO</td>
<td>3859</td>
<td>-0.18</td>
<td>100.55</td>
<td>5.0</td>
<td>107</td>
</tr>
<tr>
<td>COAL</td>
<td>3804</td>
<td>-0.14</td>
<td>49.29</td>
<td>6.39</td>
<td>1100</td>
</tr>
<tr>
<td>GAS</td>
<td>820</td>
<td>-0.16</td>
<td>6.84</td>
<td>12.29</td>
<td>610</td>
</tr>
<tr>
<td>GPV</td>
<td>4755</td>
<td>-0.21</td>
<td>16.7</td>
<td>0</td>
<td>58</td>
</tr>
<tr>
<td>HNR, HR</td>
<td>2347</td>
<td>-0.07</td>
<td>14.27</td>
<td>2.55</td>
<td>17.5</td>
</tr>
<tr>
<td>NR, NCP</td>
<td>5335</td>
<td>-0.18</td>
<td>88.75</td>
<td>2.04</td>
<td>13.4</td>
</tr>
<tr>
<td>OIL</td>
<td>1347</td>
<td>-0.15</td>
<td>30.25</td>
<td>6.45</td>
<td>850</td>
</tr>
<tr>
<td>RPV</td>
<td>6050</td>
<td>-0.21</td>
<td>26.04</td>
<td>0</td>
<td>58</td>
</tr>
<tr>
<td>WON</td>
<td>2437</td>
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<td>28.07</td>
<td>0</td>
<td>19</td>
</tr>
<tr>
<td>WOF</td>
<td>5074</td>
<td>-0.15</td>
<td>53.33</td>
<td>0</td>
<td>14</td>
</tr>
</tbody>
</table>

(s) zone). It is further assumed that other existing technologies will not reach their end of life during the plan horizon.

The capital (CC) and the O&M cost (OMV, OMF) data for the first year is shown in Table I [28]. The annual increments in CC are calculated using last 10-year data [28] [29], while for O&M costs the annual increment is assumed to be 4% (inflation rate). Table I also includes the eqCO₂ emission per unit energy produced [30]. The annual fuel cost (β_e) for COAL, OIL and GAS is taken from [28], and it is assumed to be 12 $/MWh for BIO [31], 7.5 $/MWh for NR and NCP [32], and zero for other technologies.

Capacity factors of all non-dispatchable resources, i.e., solar PV and wind, computed from [33] and [27] respectively, are shown in Table II, which also includes the zonal power generation potentials for these technologies. The GPV generation potential is computed by assuming the zonal land availability and considering a 5 kWh/m² energy density. For RPV, the number of households in each zone is estimated based on [34], and it is assumed that a maximum of 1% of them will have installed rooftop panels. The potential for wind generation is based on the most favourable sites available [26]. The maximum value of CF, attainable by dispatchable sources are assumed to be 100% for all except BIO (70%), HNR (85%), and HR (90%) [27], while a CFmin is imposed for existing capacities, i.e., 30% for BIO, COAL and HNR, and 20% for GAS and OIL. Additionally, for HR, NCP and NR, a minimum generation (ψ) of 60% at all times is assumed.

The average annual electricity market price is computed using price duration curves of Hourly Ontario Energy Price (HOEP) [27], yielding \( \mu_{b,1} = 5.08 \times 22.61 = 299.54 \) $/MWh and corresponding growth rates of 8.8%, 8.4% and 8.1% for the respective time blocks. The FIT rates, developed by the OPA in 2009 [35], are the existing incentives (\( \rho_{FIT} \)) used for BIO (151.29 $/MWh), GPV (443 $/MWh), RPV (672.25 $/MWh), WON (135 $/MWh), and WOF (190 $/MWh). Regulated prices (\( \nu \)) of HR (35 $/MWh), NR (55 $/MWh) and NCP (60 $/MWh) are from [36], [37]. Additionally, all the regulated/contract prices are assumed to have an annual growth rate equal to the base (\( b = 1 \)) growth rate of HOEP, i.e., 8.8%.

The IPSP forecasts a demand growth rate over the period 2007–2027 for base (23%), intermediate (38%) and peak (21%) load [26]. Using this information, and the zonal energy and power demands for 2011 [27], the annual growth rates are obtained and depicted in Table III, where PD growth rate is assumed to be the same as the peak energy growth rate. The IPSP also specifies a target of 1500 GWh of Ontario-wide energy conservation per year, with 10,700 MW of total capacity target for s3 technologies by 2018, and 15,700 MW of s8 technologies by 2025. Hence, (29) in the

<table>
<thead>
<tr>
<th>i</th>
<th>GPV</th>
<th>RPV</th>
<th>WON</th>
<th>WOF</th>
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<tr>
<td>CF</td>
<td>T_i</td>
<td>CF</td>
<td>T_i</td>
<td>CF</td>
</tr>
<tr>
<td>NW</td>
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<td>NE</td>
<td>13.13</td>
<td>203</td>
<td>13.7</td>
<td>12</td>
</tr>
<tr>
<td>ESSA</td>
<td>13.13</td>
<td>218</td>
<td>13.7</td>
<td>15</td>
</tr>
<tr>
<td>OTTAWA</td>
<td>15.84</td>
<td>21</td>
<td>15.98</td>
<td>19</td>
</tr>
<tr>
<td>EAST</td>
<td>15.13</td>
<td>167</td>
<td>15.7</td>
<td>24</td>
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<tr>
<td>TORONTO</td>
<td>13.7</td>
<td>30</td>
<td>13.98</td>
<td>104</td>
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<tr>
<td>NIAGARA</td>
<td>13.13</td>
<td>129</td>
<td>13.7</td>
<td>9</td>
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<tr>
<td>SW</td>
<td>13.13</td>
<td>462</td>
<td>13.7</td>
<td>50</td>
</tr>
<tr>
<td>BRUCE</td>
<td>13.13</td>
<td>173</td>
<td>13.7</td>
<td>2</td>
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<tr>
<td>WEST</td>
<td>15.13</td>
<td>464</td>
<td>15.7</td>
<td>23</td>
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TABLE III
Zonal Energy and Power Demand and their Annual Growth Rates

<table>
<thead>
<tr>
<th>i</th>
<th>ED_{i,j} [GWh]</th>
<th>Growth Rate [%]</th>
<th>PD_{i,j} [MW]</th>
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<tr>
<td></td>
<td>Base</td>
<td>Int.</td>
<td>Peak</td>
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<tr>
<td>NW</td>
<td>3066</td>
<td>1298</td>
<td>62</td>
</tr>
<tr>
<td>NE</td>
<td>7139</td>
<td>3265</td>
<td>126</td>
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<td>ESSA</td>
<td>4888</td>
<td>3350</td>
<td>201</td>
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<td>OTTAWA</td>
<td>6412</td>
<td>3110</td>
<td>272</td>
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<tr>
<td>EAST</td>
<td>5772</td>
<td>2771</td>
<td>227</td>
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<tr>
<td>TORONTO</td>
<td>33585</td>
<td>16133</td>
<td>1692</td>
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<tr>
<td>NIAGARA</td>
<td>3101</td>
<td>1433</td>
<td>172</td>
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<td>SW</td>
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<td>8198</td>
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<tr>
<td>BRUCE</td>
<td>131</td>
<td>534</td>
<td>46</td>
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<tr>
<td>WEST</td>
<td>9408</td>
<td>4538</td>
<td>474</td>
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TABLE IV
Generation Input Parameters Assumed for the GEP Model

<table>
<thead>
<tr>
<th>s</th>
<th>g_s [years]</th>
<th>CF_{0} [%]</th>
<th>CF_{Mn} [%]</th>
<th>θ_{s} [MW]</th>
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<tr>
<td>BIO</td>
<td>3</td>
<td>70</td>
<td>30</td>
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<tr>
<td>COAL</td>
<td>N</td>
<td>100</td>
<td>30</td>
<td>0</td>
</tr>
<tr>
<td>GAS</td>
<td>2</td>
<td>100</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>HNR</td>
<td>4</td>
<td>85</td>
<td>30</td>
<td>1</td>
</tr>
<tr>
<td>HR</td>
<td>4</td>
<td>90</td>
<td>60</td>
<td>50</td>
</tr>
<tr>
<td>NCP</td>
<td>6</td>
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<td>NR</td>
<td>6</td>
<td>100</td>
<td>60</td>
<td>500</td>
</tr>
<tr>
<td>GPV</td>
<td>2</td>
<td></td>
<td>Not Applicable</td>
<td>1</td>
</tr>
<tr>
<td>RPV</td>
<td>1</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>WON</td>
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<tr>
<td>WOF</td>
<td>4</td>
<td></td>
<td></td>
<td>5</td>
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</table>

TABLE V
Additional Input Parameters Assumed for the GEP Model

<table>
<thead>
<tr>
<th>b_1</th>
<th>LF</th>
<th>N</th>
<th>N_i</th>
<th>α</th>
<th>ψ_{a2}</th>
<th>φ_{Max}</th>
</tr>
</thead>
<tbody>
<tr>
<td>10%</td>
<td>5%</td>
<td>25 years</td>
<td>15 years</td>
<td>8%</td>
<td>60%</td>
<td>+π</td>
</tr>
<tr>
<td>15%</td>
<td>5%</td>
<td>25 years</td>
<td>15 years</td>
<td>8%</td>
<td>60%</td>
<td>+π</td>
</tr>
<tr>
<td>20%</td>
<td>5%</td>
<td>25 years</td>
<td>15 years</td>
<td>8%</td>
<td>60%</td>
<td>+π</td>
</tr>
<tr>
<td>25%</td>
<td>5%</td>
<td>25 years</td>
<td>15 years</td>
<td>8%</td>
<td>60%</td>
<td>+π</td>
</tr>
<tr>
<td>30%</td>
<td>5%</td>
<td>25 years</td>
<td>15 years</td>
<td>8%</td>
<td>60%</td>
<td>+π</td>
</tr>
</tbody>
</table>

The GEP model is defined as:

\[ \sum_{s=1}^{S} \sum_{i=1}^{I} Cap_{s,i,2018} \geq 10,700 \]  (40)

and

\[ \sum_{s=1}^{S} \sum_{i=1}^{I} Cap_{s,i,2025} \geq 15,700. \]  (41)

The duration of load blocks for the base (b = 1), intermediate (b = 2) and peak (b = 3) are estimated from [27] to be 43%, 51% and 6% of 8760 hrs, respectively. Other relevant input parameters are the discount rate \( \alpha = 8\% \), GRM \( b_0 = 10\% \), and emission penalty \( \zeta = 100 $/ton of eqCO_2 \). A summary of all assumed main input parameters required for the model are given in Tables IV and V.

A. Base Case (Case–0)

1) Selection of Energy Conservation Incentive Rate (a_0):

The proposed holistic GEP model is solved using CPLEX [38] in the GAMS [39] environment. The initial task is then to determine the appropriate value of \( a_0 \) for a given energy conservation target. Thus, Fig. 6 shows the effect of varying \( a_0 \) on attaining the desired energy conservation target. The results demonstrate that for \( 1 \leq a_0 \leq 35 \$$/MWh, 100\% of the targeted energy conservation is achieved even when the targets and discounted PBPs vary. By increasing \( a_0 \) above 35 \$/MWh, the plan fails to achieve the targeted level of annual energy conservation, since from the planner’s perspective, energy generation and supply becomes cheaper than the incentive payment.

Figures 7 and 8 show that variations in \( a_0 \) have no significant effect on new \( s^3 \) installations (\( NC_{s,s} \)) or their corresponding incentives (\( \phi^{Max} \)), respectively. This is important for the central planner, as it renders the decision making on \( a_0 \) basically independent from the optimal decision on \( \phi^{New} \). Therefore, \( a_0 = 35 \$$/MWh is selected for all the studies reported in this paper, so that LDCs are encouraged to implement energy conservation.

2) The Holistic Plan and Optimal Incentive Design: The holistic plan results are based on an energy conservation target of 1500 GWh/year and \( \phi^{Max} = 10 \) years. Figure 9 presents the optimal generation capacity plan obtained from the proposed holistic GEP model. Note that the main capacity additions are from wind and GAS technologies with small support from BIO, PV and HNR. The effective \( PD \) in Fig 9 is essentially the right-hand-side of (18), and corresponds to the annual Ontario demand with specified...
TABLE VI
Provincial and Zonal Incentives ($\rho_{new}^{\text{NC}}$) and IRRs with the Sizing (NC), Siting (i) and Timing (k) of the New Capacity Additions for s3 technologies

| i  | PROV  | NC   | $\rho_{new}^{\text{NC}}$ | IRR (%) | | PROV  | NC   | $\rho_{new}^{\text{NC}}$ | IRR (%) | | PROV  | NC   | $\rho_{new}^{\text{NC}}$ | IRR (%) | | PROV  | NC   | $\rho_{new}^{\text{NC}}$ | IRR (%) |
|-----|-------|------|------------------------|---------|------|-------|------------------------|---------|------|-------|------------------------|---------|------|-------|------------------------|
| NW | -     | 7    | 129 62.54             | 14.90   | -    | 1     | 69.59                 | 13.18   | -    | 1     | 107 18.78               | 17.62   | -    | 1     | 995 27.10               | 13.21   |
| NE | -     | 7    | 202 56.96             | 12.65   | -    | 1     | 71.08                 | 12.96   | -    | 1     | 935 17.07               | 18.45   | -    | 1     | 995 27.10               | 13.21   |
| ESSA | 7 | 200 27.60          | 22.03   | -    | 14   | 61.29                 | 10.68   | -    | 1     | 617 15.04               | 13.38   | -    | 1     | 995 33.47               | 13.38   |
| NIAGARA | - | 129 64.80         | 14.78   | -    | 7   | 70.28                 | 12.66   | -    | 1     | 70 12.68                | 12.68   | -    | 1     | 995 14.65               | 13.33   |
| SW | 7    | 58 28.08          | 21.57   | -    | 49   | 62.78                 | 10.95   | -    | 1     | 200 21.75               | 19.03   | -    | 1     | 995 33.47               | 13.38   |
| ONTARIO | 7 | 448 27.10         | 22.66   | -    | 213  | 59.25                 | 10.14   | 7 | 1275 17.65     | 18.51   | -    | 1     | 995 28.33               | 13.39   |

Fig. 8. Effect of $a_0$ on incentives for new s3 capacity additions $\rho_{new}^{\text{NC}}$.

Fig. 9. Optimal generation capacity plan to supply the effective peak demand.

Fig. 10. Energy supply-demand balance including energy conservation.

GRM, minus the demand reduction target. Similarly, the optimal annual energy supply-demand balance is shown in Fig. 10, where the effective energy demand is the actual provincial energy demand minus the energy conservation achieved. Observe that the optimal energy supply mix results in a reduced contribution from nuclear generation in order to accommodate energy generation from non-dispatchable resources.

The holistic GEP solution suggests, as shown in Tables VI and VII, that only incentive driven and market price based technologies are economically viable for future installations. Table VI shows the optimal incentive rates with respective IRR for s3 technologies, along with the sizing, siting and timing of their new installations. It is found that the provincial $\rho_{new}^{\text{NC}}$ are higher than $\rho_{Ex}^{\text{NC}}$, which indicates that the existing incentives (FIT 1.0) have higher PBPs and, consequently, lower IRRs than the proposed ones. It is also found (see Fig. 10) that energy generation from gas increases continuously since the installation of new capacities, which is also reflected in their very small PBPs, as shown in Table VII.

It is important to highlight the fact that, as mentioned towards the end of Section II, a CPA, a regulator, or a regional planning authority is expected to use the proposed GEP model. However, the GENCOs’ interest are also considered by including a maximum limit on their respective PBP. Thus, the proposed model’s objective is to determine the optimal incentives for RES integration from a CPA’s...
perspective, while considering the GENCOs investment constraints. Therefore, any reduction in incentives will increase PBP of the GENCOs, which will hence reduce RES investments, and thus increase CPA’s total costs. Similarly, any increase in incentives will render the RES technologies more expensive than the non-RES ones, and again increase CPA’s total costs.

B. Case Studies: Presence/Absence of Targets

The following case studies are constructed to examine the effect of inclusion or exclusion of plan targets on the GEP results:

Case–1: No energy conservation target.

Case–2: No capacity target for s3 technologies.

Case–3: No capacity target for RES (s8) technologies.

Case–4: No capacity or energy conservation target, i.e., business-as-usual (BAU) case.

Fig. 11 shows that minimum emission occurs in Case-0, increases gradually as the targets are progressively removed (from Case-1 to Case-3), and is maximum when both targets are excluded from the GEP model (Case-4), thereby confirming the need for introduction of RES and energy conservation. A comparison of the optimal costs and payments, i.e., R, C, EC and ECP, depicted in Table VIII, shows that Case-0 is not the cheapest option from the CPA’s point of view; it also indicates that forceful integration of RES using incentives is expensive than the BAU (Case-4) scenario. The difference in the plan cost (\(\Omega\)) is not due to the relatively higher than market-price values of the incentives, as is the general conception, but largely due to the excess capacity addition decisions (with respect to PD) made in cases with RES capacity targets.

C. Uncertainty Analysis

A Monte Carlo Simulation procedure was carried out and the results are presented here to examine the effect of uncertainties in solar and wind generation availabilities on plan decisions. The annual average CFs of GPV, RPV, WON, and WOF for each zone are perturbed simultaneously considering a normal distribution with standard deviations of 20% for each, while the means correspond to the deterministic values previously used. Note that this results in significant broad range of variations in CFs as shown in Table IX.

The results of Monte Carlo simulations are shown in Table X, which includes the range, standard deviation, mean, and
percentage standard deviation of the probability density function of target output variables, \( NC \), and \( \rho_{\text{New}} \); the table also includes the NPV of costs and payments and total emissions. Observe that the percentage standard deviations of plan costs and payments \( (R, C, EC, \text{and } \Omega) \) are low, as depicted in Fig. 12, showing that significant \( CF \) variations do not have a large impact on the system costs and payments. Note as well that the \( CF \) variations have little effect on the resulting capacity addition or optimal incentive design for BIO (Fig. 13a). Thus, one can conclude that the uncertainties in solar and wind energy availability affect the capacity addition and incentive design for mostly solar and wind technologies. Observe also that WON capacity additions remain un-altered at its maximum province-wide potential, not decreasing at lower capacity factors, and thereby establishing itself as a techno-economically proven RES. On the other hand, the optimal incentive design for WON varies with a log-normal distribution (Fig. 13b), indicating that for lower \( CF \) values, high incentive rates are required to maintain the same amount of capacity additions.

![Fig. 12. System costs and payments from Monte Carlo simulations.](image1)

![Fig. 13. Variation in RES incentives (¢/kWh) for bio and wind generation from Monte Carlo simulations.](image2)

<table>
<thead>
<tr>
<th>TABLE X</th>
<th>MAIN OUTPUT VARIABLES OF MONTE CARLO SIMULATIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total planned capacity additions [MW]</strong></td>
<td></td>
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<tr>
<td>BIO</td>
<td>447</td>
</tr>
<tr>
<td>GPV</td>
<td>1242</td>
</tr>
<tr>
<td>RPV</td>
<td>18</td>
</tr>
<tr>
<td>WON</td>
<td>1275</td>
</tr>
<tr>
<td>WOF</td>
<td>4015</td>
</tr>
<tr>
<td>GAS</td>
<td>3000</td>
</tr>
<tr>
<td>HNR</td>
<td>190</td>
</tr>
</tbody>
</table>

| **RES incentives [¢/kWh]** | | |
| BIO | 21.54 | 0.53 | 26.89 | 32.69 | 1.97 |
| GPV | 44.95 | 4.22 | 57.60 | 72.92 | 7.32 |
| RPV | 43.09 | 5.45 | 59.89 | 87.47 | 9.10 |
| WON | 12.73 | 2.25 | 17.75 | 29.31 | 12.69 |
| WOF | 22.48 | 3.19 | 31.69 | 44.91 | 10.06 |

| | NPV of \( R \) [Billion $] | 196.01 | 8.64 | 199.38 | 202.49 | 0.433 |
| | NPV of \( C \) [Billion $] | 84.01 | 0.74 | 86.78 | 91.01 | 0.849 |
| | NPV of \( EC \) [Billion $] | 22.33 | 0.40 | 23.74 | 24.99 | 1.68 |
| | Plan Cost \( \Omega \) [Billion $] | 304.66 | 1.69 | 311.02 | 316.52 | 0.543 |
Finally, note that capacity additions of PV technologies, particularly RPV, vary significantly with changes in their CFs, as shown in Fig. 14.

V. CONCLUSIONS

A novel holistic GEP model was proposed to determine the optimal RES incentive rates to be offered to GENCOs in order to achieve a target renewable penetration level, along with the incentives for LDCs to maintain a specified energy conservation level. The application of the proposed model to a realistic test case based on available data for Ontario, Canada, demonstrated the feasibility and benefits of the developed model.

This work is an important step toward designing suitable incentives and targets for RES capacity penetration and energy conservation to achieve reduced emissions at minimal system costs. An important conclusion of the work is that the selection of energy conservation incentive ($\alpha_0$) and the optimal design of RES incentives ($\rho^{\text{New}}$) are mutually exclusive, thus allowing the system planner to specify the respective targets independently.

REFERENCES


Fig. 14. Variation in solar PV incentives from Monte Carlo simulations.
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