Optimal Incentive Design for Targeted Penetration of Renewable Energy Sources

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***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

BAU	Business-as-Usual
BIO	Bio-based power generation
COAL	Coal-based power generation
CPA	Central Planning Authority
DSM	Demand Side Management
FIT	Feed-in-Tariff
GAS	Gas-based power generation
GENCO	Generation Company
GEP	Generation Expansion Planning
GPV	Ground-mounted PV based power generation
GRM	Generation Reserve Margin
HNR	Market-price-based hydro power generation
HOEP	Hourly Ontario Energy Price
HR	Regulated-price-based hydro power generation
IPSP	Integrated Power System Plan
IRP	Integrated Resource Planning
IRR	Internal Rate of Return
LDC	Local Distribution Company
MILP	Mixed Integer Linear programming
MINLP	Mixed Integer Non-linear Programming
NCP	Contract-price-based nuclear power generation
NPV	Net Present Value
NR	Regulated-price-based nuclear power generation
OIL	Oil-based power generation
O&M	Operation and Maintenance
OPA	Ontario Power Authority
PBP	Payback Period
PV	Photo-voltaic
RES	Renewable Energy Sources
RPV	Roof-top PV based power generation
WON	Onshore wind based power generation
WOF	Offshore wind based power generation

Superscripts

Ex	Quantities related to existing capacities
Max	Maximum value of a data set
Min	Minimum value of a data set
New	Quantities related to new capacities

Sets and Indices

i, j	Index of transmission system zones
k	Index of planning years
q	Index for binary variables
s	Set of all generation technologies
$s1$	Set of technologies receiving market price based payments from Central Planning Authority (CPA)
$s2$	Set of technologies receiving payments from CPA based on regulated price
$s3$	Set of technologies receiving payments from CPA based on incentives
$s4$	Set of technologies connected at distribution level
$s5$	Set of technologies connected at transmission level
$s6$	Set of dispatchable generation technologies
$s7$	Set of non-dispatchable generation technologies
$s8$	Set of renewable energy sources based technologies
b	Index for base, intermediate and peak load blocks

Parameters

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

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$Cap^{Ex}_{s,k,i}$	Existing capacities over the plan horizon [MW]
$CC_{s,k}$	Capital cost [$/kW]
$CF_{s,i}$	Capacity factor [%]
CF^{Min}_{s6}	Minimum capacity factor for existing sources [%]
Δt_b	Time duration of load blocks [hours]
$ED_{k,i,b}$	Energy demand [MWh]
Em_s	Emission rate [kg of $eq\mathrm{CO_2}$/MWh]
g_s	Gestation period [years]
LF	Transmission loss factor [%]
N_1	Period of new installations [years]
N	Plan horizon [years]
$OMF_{s,k}$	Fixed O&M cost [$/kW]
$OMV_{s,k}$	Variable O&M cost [$/MWh]
$PD_{k,i}$	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
α	Discount rate [%]
$\beta_{s,k}$	Fuel prices [$/MWh]
$\mu_{k,b}$	Average annual electricity market price [$/MWh]
$\nu_{s2,k}$	Regulated price [$/MWh]
$\phi^{Max}_{s3,i}$	Maximum payback period limit [years]
$\rho^{Ex}_{s3,i}$	Incentive rates for existing capacities [$/MWh]
ψ_{s2}	Minimum power generation at all time [%]
θ	Capital recovery factor
ζ	Emission penalty [$ / ton of $eq\mathrm{CO_2}$]
ϑ_s	Unit size of new capacity additions [MW]
ϖ	Target penetration level of *s8* technologies [%]
$\Gamma_{s,i}$	Zonal capacity addition potentials [MW]
$\Upsilon_{s,k}$	Annual energy generation potentials [MWh]

Variables

$C_{s,k,i}$	O&M, Fuel and installation costs [$]
$Cap_{s,k,i}$	Capacities available to generate energy [MW]
$CFL_{s,k,i}$	Fuel costs [$]
$CI_{s,k,i}$	Installation costs of new capacity additions [$]
$CN_{k,i,b}$	Energy conservation [GWh]
$COM_{s,k,i}$	O&M costs [$]
$DR_{k,i,b}$	Demand reduction [MW]
$E_{s,k,i,b}$	Energy generations [MWh]
$EC_{s,k,i}$	Emission cost [$]
$ECP_{k,i}$	Incentive payments for energy conservation [$]
$ET_{k,i,j,b}$	Energy transfer between zones [MWh]
$NC_{s,k,i}$	New capacity installations (integer) [MW]
$R_{s,k,i}$	CPA's payment to GENCOs using μ, ν or ρ [$]
$W_{s,k,i,q}$	Binary variables
$\delta_{k,i,b}$	Bus angles [rad]
$\phi_{s3,i}$	Discounted payback period [years]
$\rho^{New}_{s3,i}$	Incentive rate for new capacities [$/MWh]
Ω	NPV of total costs and paymets [$]

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. 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-á-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.

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 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 novel model enforces an acceptable return from investments in RES technologies for GENCOs by incorporating a maximum payback-period (PBP) limit for RES investments, which in turn ensures a minimum internal rate of return (IRR), thereby encouraging investments in RES.
- The proposed new 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 zones to adequately represent the main transmission corridors, load variations in different locations, and regional availabilities of solar, wind, and/or hydro generation.

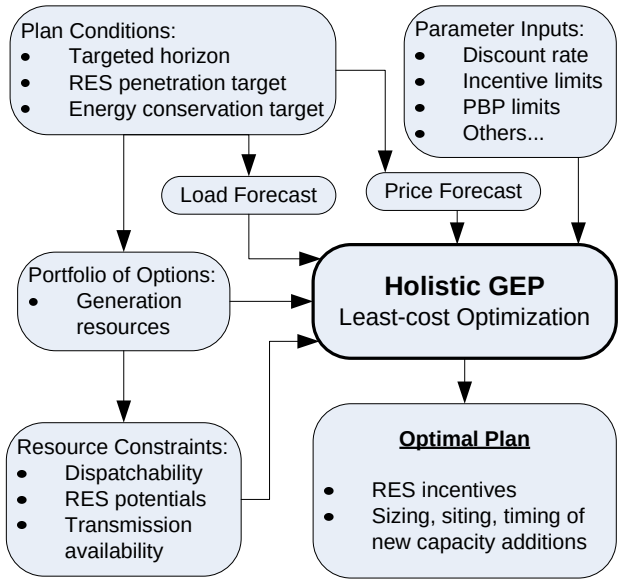


Fig. 1. Framework of the proposed holistic GEP.

- 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 α; cost of emission per unit energy ζ; generation reserve margin b_0; gestation period g_s; installation plan period N_1; minimum capacity factor for dispatchable sources CF_{s6}^{Min}; RES incentive rates limits ρ_{Max}^{New} and ρ_{Min}^{New}; payback-period limits ϕ^{Max} and ϕ^{Min}; and unit size of installation for new capacity additions ϑ_s.

B. Planning Objective

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

$$\Omega = \sum_{s}\sum_{k=1}^{N}\sum_{i=1}^{Z}\frac{R_{s,k,i}+C_{s,k,i}+EC_{s,k,i}}{(1+\alpha)^k}+\sum_{k=1}^{N}\sum_{i=1}^{Z}\frac{ECP_{k,i}}{(1+\alpha)^k} \quad (1)$$

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:

$$R_{s,k,i} = \underbrace{R_{s1,k,i}^{Ex}+R_{s2,k,i}^{Ex}+R_{s3,k,i}^{Ex}}_{R_{s,k,i}^{Ex}}+\underbrace{R_{s1,k,i}^{New}+R_{s2,k,i}^{New}+R_{s3,k,i}^{New}}_{R_{s,k,i}^{New}}. \quad (2)$$

These payments may be based on the market price (μ) or regulated price (ν) or incentives (ρ), and are computed as:

$$R_{s,k,i}^{Ex} = \underbrace{\sum_{b=1}^{3}\mu_{k,b}E_{s1,k,i,b}^{Ex}}_{R_{s1,k,i}^{Ex}}+\underbrace{\sum_{b=1}^{3}\nu_{s2,k}E_{s2,k,i,b}^{Ex}}_{R_{s2,k,i}^{Ex}}+\underbrace{\rho_{s3,i}^{Ex}\sum_{b=1}^{3}E_{s3,k,i,b}^{Ex}}_{R_{s3,k,i}^{Ex}} \quad (3)$$

$$R_{s,k,i}^{New} = \underbrace{\sum_{b=1}^{3}\mu_{k,b}E_{s1,k,i,b}^{New}}_{R_{s1,k,i}^{New}}+\underbrace{\sum_{b=1}^{3}\nu_{s2,k}E_{s2,k,i,b}^{New}}_{R_{s2,k,i}^{New}}+\underbrace{\rho_{s3,i}^{New}\sum_{b=1}^{3}E_{s3,k,i,b}^{New}}_{R_{s3,k,i}^{New}} \quad (4)$$

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

$$E_{s,k,i,b} = E_{s,k,i,b}^{Ex} + E_{s,k,i,b}^{New}. \quad (5)$$

The decision variables $\rho_{s3,i}^{New}$ 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:

$$C_{s,k,i} = CI_{s,k,i} + CFL_{s,k,i}^{Ex} + CFL_{s,k,i}^{New} + COM_{s,k,i}^{Ex} + COM_{s,k,i}^{New} \quad (6)$$

where CI for all generation technologies is computed using:

$$CI_{s,k,i} = NC_{s,k,i}\, CC_{s,k}. \quad (7)$$

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

$$CFL_{s,k,i}^{Ex} + CFL_{s,k,i}^{New} = \beta_{s,k}\left(\sum_{b=1}^{3}E_{s,k,i,b}^{Ex}+\sum_{b=1}^{3}E_{s,k,i,b}^{New}\right) \quad (8)$$

and the COM for existing and new technologies is given by:

$$COM_{s,k,i}^{Ex} + COM_{s,k,i}^{New} = OMF_{s,k}\left(Cap_{s,k,i}^{Ex}+Cap_{s,k,i}^{New}\right) + OMV_{s,k}\left(\sum_{b=1}^{3}E_{s,k,i,b}^{Ex}+\sum_{b=1}^{3}E_{s,k,i,b}^{New}\right) \quad (9)$$

where the generation capacities are obtained as follows:

$$Cap_{s,k,i} = Cap_{s,k,i}^{Ex} + Cap_{s,k,i}^{New}. \quad (10)$$

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

$$EC_{s,k,i} = \zeta Em_s \sum_{b=1}^{3}E_{s,k,i,b} \quad (11)$$

where Em is the equivalent CO_2 emission ($eq CO_2$) per unit energy generation from various technologies, and ζ is the penalty (cost) per unit emission.

The incentive payments (ECP) on energy conservation (CN) and demand reduction (DR), given in (1), are calculated as:

$$ECP_{k,i} = a_0\sum_{b=1}^{3}CN_{k,i,b} + \sum_{b=1}^{3}a_b DR_{k,i,b} \quad (12)$$

where DR is related to CN as follows:

$$CN_{k,i,b} = DR_{k,i,b}\Delta t_b \quad (13)$$

assuming that $a_b = a_0\Delta t_b$, 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_b) 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:

$$\sum_{s5} E_{s5,k,i,b} - \sum_{j=1}^{Z} ET_{k,i,j,b} + \sum_{j=1}^{Z} ET_{k,j,i,b}(1-LF) = \left(ED_{k,i,b} - \sum_{s4} E_{s4,k,i,b} \right) - CN_{k,i,b} \quad (14)$$

where $s4 \cup s5 = s$, and ET, a positive decision variable, is related to bus voltage angles by the following dc power flow equations:

$$ET_{k,i,j,b} = B_{k,i,j}(\delta_{k,i,b} - \delta_{k,j,b})\Delta t_b. \quad (15)$$

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

$$ET_{k,i,j,b} \leq PT^{Max}_{k,i,j} \Delta t_b \quad (16)$$

$$\delta^{Min} \leq \delta_{k,i,b} \leq \delta^{Max}. \quad (17)$$

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:

$$\sum_{s} \sum_{i=1}^{Z} Cap_{s,k,i} \geq (1+b_0) \sum_{i=1}^{Z} PD_{k,i} - \sum_{i=1}^{Z} DR_{k,i,\text{“3”}} \quad (18)$$

where b_0 (GRM) is a given percentage of peak demand.

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

$$Cap^{New}_{s,k+1,i} = NC_{s,k,i} + Cap^{New}_{s,k,i} \quad (19)$$

where the timing for new installations are bounded by g_s and N_1 as follows:

$$NC_{s,k,i} = 0$$
$$\forall \quad k = 1, \ldots, g_s, (N_1+1), \ldots, N \quad \text{and} \quad N_1 > g_s. \quad (20)$$

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 intiation 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:

$$\sum_{b=1}^{3} E_{s6,k,i,b} \leq 8760 \; CF_{s6} Cap_{s6,k,i} \quad (21)$$

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

$$\sum_{b=1}^{3} E_{s7,k,i,b} = 8760 \; CF_{s7,i} Cap_{s7,k,i} \quad (22)$$

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.

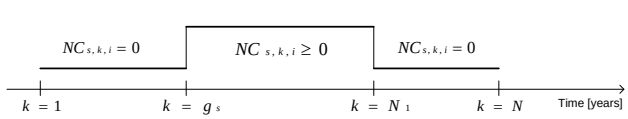


Fig. 2. Dynamic new capacity additions.

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:

$$\sum_{t=1}^{3} E^{Ex}_{s6,k,i,t} \geq 8760 \; CF^{Min}_{s6} Cap^{Ex}_{s6,k,i}. \quad (23)$$

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

$$E_{s,k,i,b}/\Delta t_b \leq Cap_{s,k,i}. \quad (24)$$

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

$$E_{s2,k,i,b}/\Delta t_b \geq \psi_{s2} \; Cap_{s2,k,i}. \quad (25)$$

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:

$$\phi^{Min}_{s3,i} \leq \phi_{s3,i} \leq \phi^{Max}_{s3,i}. \quad (26)$$

Here, ϕ is computed using the following non-linear equation:

$$\phi_{s3,i} = \frac{\sum_{k=1}^{N} \frac{CI_{s3,k,i}}{(1+\alpha)^k}}{\left(\sum_{k=1}^{N} \frac{R^{New}_{s3,k,i} - \left(COM^{New}_{s3,k,i} + CFL^{New}_{s3,k,i} \right)}{(1+\alpha)^k} \right) \theta} \quad (27)$$

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 θ.

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

$$NC_{s,k,i} = \sum_{q=1}^{Q_s} \vartheta_s W_{s,k,i,q} \quad (28)$$

where ϑ_s is the unit size of installation for new capacity additions and W is a binary variable.

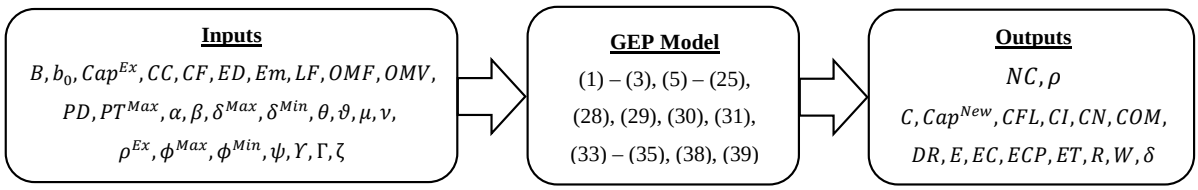


Fig. 3. Inputs and output variables and equations of the proposed GEP model.

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

$$\sum_{s8}\sum_{i=1}^{Z} Cap_{s8,k,i} \geq \varpi \sum_{s}\sum_{i=1}^{Z} Cap_{s,k,i} \quad \text{for} \quad k = N_1 \tag{29}$$

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

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

$$\sum_{i=1}^{Z}\sum_{b=1}^{3} E_{s,k,i,b} \leq \Upsilon_{s,k} \tag{30}$$

$$\sum_{k=1}^{N} NC_{s,k,i} \leq \Gamma_{s,i}. \tag{31}$$

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 an Mixed Integer Non-Linear Programming (MINLP) planning problem, to simplify it to an 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:

$$R^{New}_{s3,k,i} = \rho^{New}_{s3,i} \sum_{b=1}^{3} E^{New}_{s3,k,i,b} \tag{32}$$

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

$$R^{New}_{s3,k,i} \leq \rho^{New}_{Max} \sum_{b=1}^{3} E^{New}_{s3,k,i,b} \tag{33}$$

$$R^{New}_{s3,k,i} \geq \rho^{New}_{Min} \sum_{b=1}^{3} E^{New}_{s3,k,i,b}. \tag{34}$$

Hence, (4) is replaced by the following:

$$R^{New}_{s1,k,i} + R^{New}_{s2,k,i} = \sum_{b=1}^{3} \mu_{k,b} E^{New}_{s1,k,i,b} + \sum_{b=1}^{3} \nu_{s2,k} E^{New}_{s2,k,i,b} \tag{35}$$

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

The zonal values of $\rho^{New}_{s3,i}$ for the incentive-driven sources can later be calculated from the model solution using:

$$\rho^{New}_{s3,i} = \frac{\sum_{k=1}^{N} R^{New}_{s3,k,i}}{\sum_{k=1}^{N}\sum_{b=1}^{3} E^{New}_{s3,k,i,b}} \tag{36}$$

and the province-wide values of ρ^{New}_{s3} can later be computed as follows:

$$\rho^{New}_{s3} = \frac{\sum_{k=1}^{N}\sum_{i=1}^{Z} R^{New}_{s3,k,i}}{\sum_{k=1}^{N}\sum_{i=1}^{Z}\sum_{b=1}^{3} E^{New}_{s3,k,i,b}}. \tag{37}$$

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

$$\sum_{k=1}^{N} \frac{CI_{s3,k,i}}{(1+\alpha)^k} \leq \phi^{Max}_{s3,i} \left(\sum_{k=1}^{N} \frac{R^{New}_{s3,k,i} - \left(COM^{New}_{s3,k,i} + CFL^{New}_{s3,k,i}\right)}{(1+\alpha)^k} \right) \theta \tag{38}$$

$$\sum_{k=1}^{N} \frac{CI_{s3,k,i}}{(1+\alpha)^k} \geq \phi^{Min}_{s3,i} \left(\sum_{k=1}^{N} \frac{R^{New}_{s3,k,i} - \left(COM^{New}_{s3,k,i} + CFL^{New}_{s3,k,i}\right)}{(1+\alpha)^k} \right) \theta. \tag{39}$$

Then, ϕ 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), (33) 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 ($B_{k,i,j}$, $PT^{Max}_{k,i,j}$) is taken from [25], along with an assumed transmission loss factor (*LF*) of 5%.

The set of market price based technologies (*s1*) 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

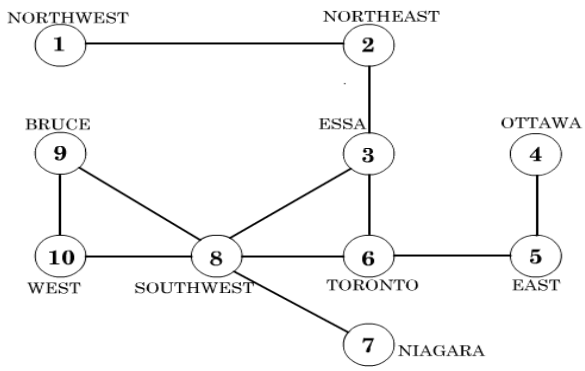


Fig. 4. Ontario transmission zones [24].

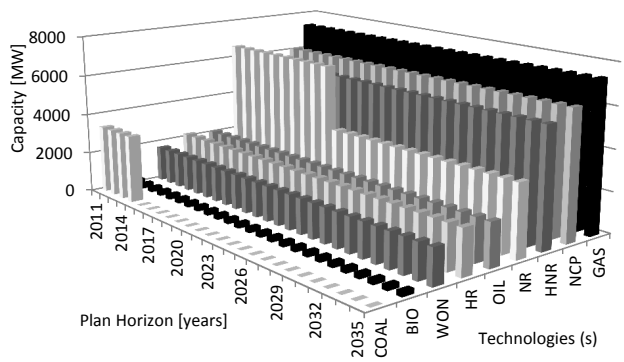


Fig. 5. Existing capacities over the plan horizon [26], [27].

TABLE I
CAPITAL AND O&M COSTS OF GEN. TECHNOLOGIES AND CO_2 EMISSION [28]

s	$CC_{s,1}$		$O\&M$		Em_s
	Cost [$/kW]	Increment [%]	$OMF_{s,1}$ [$/kW]	$OMV_{s,1}$ [$/MWh]	[Kg of eqCO$_2$ per MWh]
BIO	3859	-0.18	100.55	5.0	107
COAL	3804	-0.14	49.29	6.39	1100
GAS	820	-0.16	6.84	12.29	610
GPV	4755	-0.21	16.7	0	58
HNR, HR	2347	-0.07	14.27	2.55	17.5
NR, NCP	5335	-0.18	88.75	2.04	13.4
OIL	1347	-0.15	30.25	6.45	850
RPV	6050	-0.21	26.04	0	58
WON	2437	-0.11	28.07	0	19
WOF	5974	-0.15	53.33	0	14

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 eqCO$_2$ emission per unit energy produced [30]. The annual fuel cost (β_k) 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/m^2 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_i attainable by dispatchable sources are assumed to be 100% for all except BIO (70%), HNR (85%), and HR (90%) [27], while a CF^{Min} 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.

TABLE II
ZONAL CAPACITY FACTORS AND POTENTIALS OF NON-DISPATCHABLE SOURCES

i	GPV		RPV		WON		WOF	
	CF_i [%]	Γ_i [MW]	CF_i [%]	Γ_i [MW]	CF_i [%]	Γ_i [MW]	CF_i [%]	Γ_i [MW]
NW	13.7	130	14.27	7	29.21	107	34.62	0
NE	13.13	203	13.7	12	33.4	935	38.83	1495
ESSA	13.13	218	13.7	15	32.16	0	37.57	0
OTTAWA	15.84	21	15.98	19	30.92	0	0	0
EAST	15.13	167	15.7	24	34.36	0	40.04	0
TORONTO	13.7	30	13.98	104	31.4	0	35.7	0
NIAGARA	13.13	129	13.7	9	24.22	0	28.18	0
SW	13.13	462	13.7	50	26.91	200	31.31	2030
BRUCE	13.13	173	13.7	2	36.05	0	41.53	405
WEST	15.13	464	15.7	23	36.97	33	42.63	1945

The average annual electricity market price is computed using price duration curves of Hourly Ontario Energy Price (HOEP) [27], yielding $\mu_{1,b}$ = [5.08 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 (ρ^{Ex}) used for BIO (151.29 $/MWh), GPV (443 $/MWh), RPV (672.25 $/MWh), WON (135 $/MWh), and WOF (190 $/MWh). Regulated prices (ν) 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 III
ZONAL ENERGY AND POWER DEMAND AND THEIR ANNUAL GROWTH RATES

i	$ED_{1,i,t}$ [GWh]			Growth Rate [%]			$PD_{1,i}$
	Base	Int.	Peak	Base	Int.	Peak	[MW]
NW	3066	1298	62	0.05	0.26	0.18	728
NE	7139	3265	126	−0.28	−0.36	−0.27	1710
ESSA	4888	3350	201	0.86	1.41	0.93	1612
OTTAWA	6412	3110	272	0.93	1.74	1.55	1874
EAST	5772	2771	227	0.56	0.99	0.47	1647
TORONTO	33585	16133	1692	1.11	1.73	1.02	10285
NIAGARA	3101	1433	172	0.56	0.88	0.51	970
SW	18930	8198	562	1.11	1.7	0.89	4873
BRUCE	131	534	46	0.48	0.85	0.63	210
WEST	9408	4538	474	1.05	1.47	0.99	2886

TABLE IV
GENERATION INPUT PARAMETERS ASSUMED FOR THE GEP MODEL

s	g_s [years]	CF_{s6} [%]	CF_{s6}^{Min} [%]	ϑ_s [MW]
BIO	3	70	30	1
COAL	N	100	30	0
GAS	2	100	20	20
HNR	4	85	30	1
HR	4	90	60	50
NCP	6	100	60	500
NR	6	100	60	500
GPV	2	Not Applicable		1
RPV	1			1
WON	3			1
WOF	4			5

TABLE V
ADDITIONAL INPUT PARAMETERS ASSUMED FOR THE GEP MODEL

b_0	LF	N	N_1	α	ψ_{s2}	δ^{Max}
10%	5%	25 years	15 years	8%	60%	$+\pi$
$\phi_{s3,i}^{Max}$	$\phi_{s3,i}^{Min}$	ζ		ρ_{Max}^{New}	ρ_{Min}^{New}	δ^{Min}
10 years	2 years	\$100/ton of $eq\mathrm{CO_2}$		\$1000/MWh	\$1/MWh	$-\pi$

GEP model is defined as:

$$\sum_{s3}\sum_{i=1}^{Z} Cap_{s3,\text{“2018”},i} \geq 10,700 \tag{40}$$

and

$$\sum_{s8}\sum_{i=1}^{Z} Cap_{s8,\text{“2025”},i} \geq 15,700. \tag{41}$$

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 α = 8%, GRM b_0 = 10%, and emission penalty ζ = 100 \$/ton of $eq\mathrm{CO_2}$. 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.

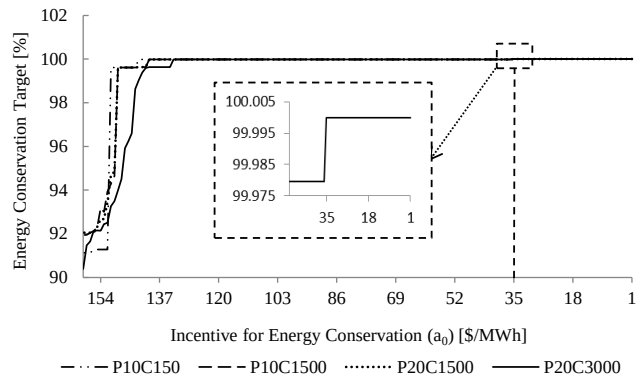


Fig. 6. Designing the energy conservation incentives: (P10C150 means PBP = 10 years, and conservation target = 150 GWh/year).

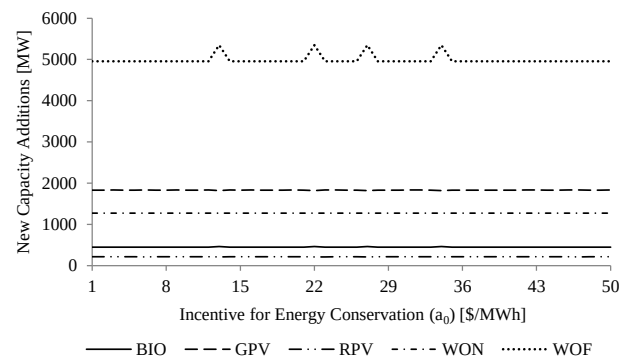


Fig. 7. Effect of a_0 on new *s3* capacity additions NC_{s3}.

Figures 7 and 8 show that variations in a_0 have no significant effect on new *s3* installations (NC_{s3}) or their corresponding incentives (ρ_{s3}^{New}), respectively. This is important for the central planner, as it renders the decision making on a_0 basically independent from the optimal decision on ρ_{s3}^{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 ϕ^{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 (ρ^{New}) AND IRRS WITH THE SIZING (NC), SITING (i) AND TIMING (k) OF THE NEW CAPACITY ADDITIONS FOR *s3* TECHNOLOGIES

i	BIO				GPV				RPV				WON				WOF			
	k	NC [MW]	ρ^{New} [¢/kWh]	IRR [%]	k	NC [MW]	ρ^{New} [¢/kWh]	IRR [%]	k	NC [MW]	ρ^{New} [¢/kWh]	IRR [%]	k	NC [MW]	ρ^{New} [¢/kWh]	IRR [%]	k	NC [MW]	ρ^{New} [¢/kWh]	IRR [%]
NW	-				7	129	62.54	14.90	7	1	69.59	13.18	7	107	18.78	17.62	-			
NE	-				7	202	56.96	12.65	7	1	71.08	12.96	7	935	17.07	18.45	7	995	27.10	13.21
ESSA	7	200	27.60	22.03	7	217	53.48	11.68	7	14	61.29	10.68	-				-			
OTTAWA	7	15	18.20	14.65	7	20	55.49	15.35	7	18	51.83	10.40	-				-			
EAST	7	150	26.86	24.29	7	167	57.60	15.20	7	24	55.54	11.15	-				-			
TORONTO	7	25	27.77	25.24	7	29	62.57	14.90	7	103	59.25	10.40	-				-			
NIAGARA	-				7	129	64.80	14.78	6	1	70.28	12.66	-				-			
									7	2		12.68								
SW	7	58	28.08	21.57	7	461	56.96	12.65	7	49	62.78	10.95	7	200	21.75	19.03	5	30	33.47	13.25
																	6	995		13.38
																	7	995		13.33
BRUCE	-				5	16	48.38	10.22	-				-				7	405	25.72	13.67
					7	1														
WEST	-				7	463	50.49	12.99	-				5	33	12.17	13.84	6	540	24.70	13.45
																	7	995		13.41
ONTARIO	7	**448**	**27.10**	**22.66**	5,7	**1834**	**55.75**	**13.21**	6,7	**213**	**59.25**	**10.14**	5,7	**1275**	**17.65**	**18.51**	5,6,7	**4955**	**28.33**	**13.39**

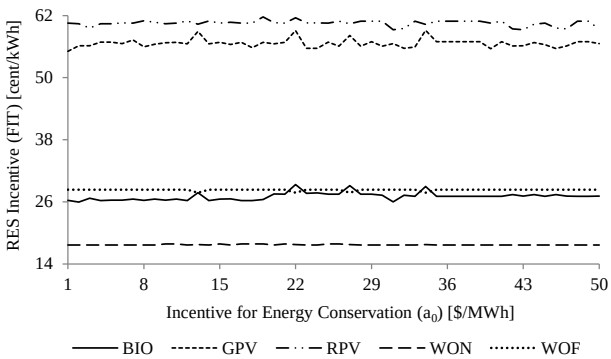


Fig. 8. Effect of a_0 on incentives for new s3 capacity additions ρ_{s3}^{New}

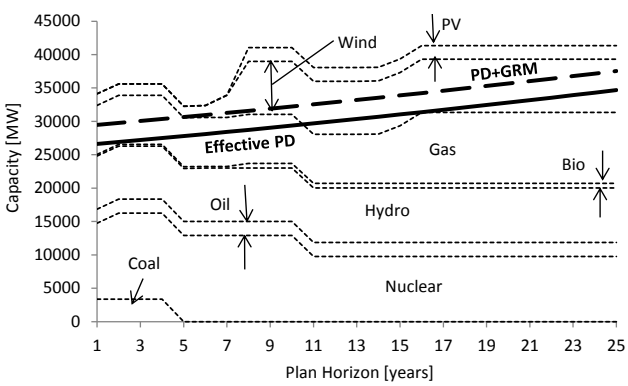


Fig. 9. Optimal generation capacity plan to supply the effective peak demand.

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 of the energy conservation achieved. Observe that the optimal energy supply mix results in a reduced contribution from nuclear generation in order to

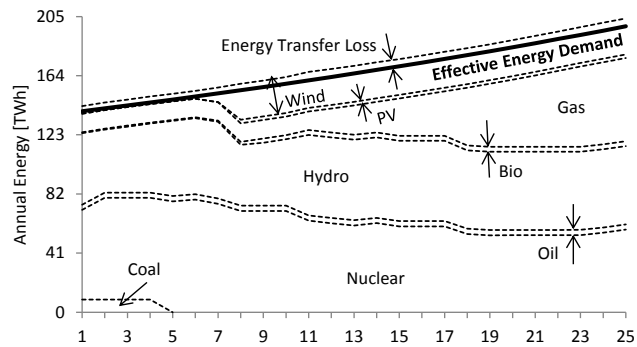


Fig. 10. Energy supply-demand balance including energy conservation.

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 ρ_{s3}^{New} are higher than ρ_{s3}^{Ex}, 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

TABLE VII
SIZE (NC), SITE (i), TIME (k) AND PBP (ϕ) OF NEW MARKET–BASED TECHNOLOGIES

s1	*i*→	ESSA	OTTAWA			EAST	TORONTO		NIAGARA	SW
GAS	*k*	-	13	14	15	-	14	15	-	-
	NC [MW]		40	260	1000		1000	1000		
	ϕ [years]		2				2			
HNR	*k*	10	5			10	-		10	10
	NC [MW]	39	41			85			16	9
	ϕ [years]	6	4			5			9	7

Fig. 11. Variation in annual emission from all technologies.

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 (Ω) 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.

TABLE VIII
CASE STUDIES: CAPACITY ADDITIONS, PBPS, INCENTIVES AND COSTS

Case studies →		Case-0	Case-1	Case-2	Case-3	Case-4
GAS	*NC* [MW]	3300	3860	6320	6340	6960
	ϕ [years]	2	2	2	2	2
HNR	*NC* [MW]	190	190	2148	190	190
	ϕ [years]	4	4	21	4	4
HR	*NC* [MW]	-	-	1900	-	-
	ϕ [years]	-	-	7	-	-
BIO	*NC* [MW]	448	448	-	-	-
	ρ^{New} [¢/kWh]	27.10	26.48	-	-	-
GPV	*NC* [MW]	1834	1825	-	-	-
	ρ^{New} [¢/kWh]	55.75	54.48	-	-	-
RPV	*NC* [MW]	213	217	-	-	4
	ρ^{New} [¢/kWh]	59.25	64.89	-	-	52.90
WON	*NC* [MW]	1275	1275	1275	1275	1275
	ρ^{New} [¢/kWh]	17.65	17.49	15.85	15.85	18.06
WOF	*NC* [MW]	4955	4960	440	-	-
	ρ^{New} [¢/kWh]	28.33	28.98	28.82	-	-
Excess capacity [%]		21.18	22.82	20.79	8.26	10.09
NPV of R [Billion $]		200.95	211.31	198.16	198.56	208.98
NPV of C [Billion $]		85.85	86.39	67.21	63.20	64.36
NPV of EC [Billion $]		22.08	22.25	25.12	25.34	25.86
NPV of ECP [Billion $]		1.12	0	1.12	1.12	0
Plan cost Ω [Billion $]		310	319.95	291.61	288.22	298.68

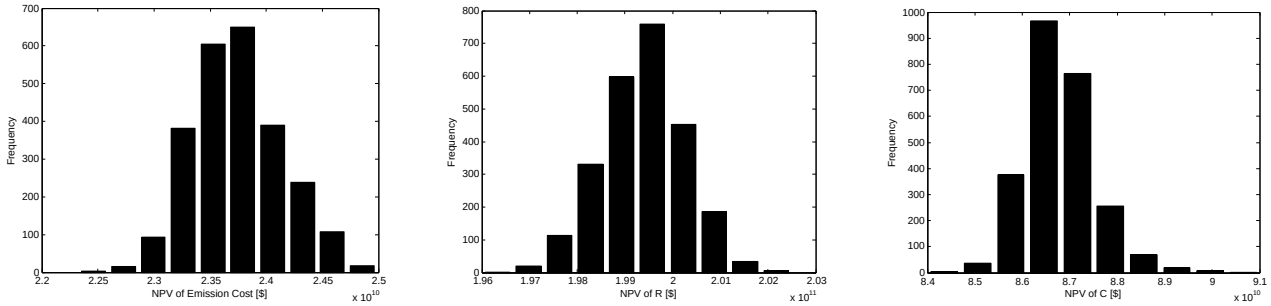
TABLE IX
RANGE OF SOLAR AND WIND ZONAL *CF* PERTURBATIONS

$CF_{s,i}$ [%]	GPV		RPV		WON		WOF	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
NW	5.79	23.24	5.59	25.32	8.23	49.89	6.86	51.80
NE	4.35	22.76	3.85	21.66	14.21	55.78	6.69	55.35
ESSA	5.31	23.04	4.63	23.46	11.00	53.47	11.66	53.28
OTTAWA	6.26	27.82	6.00	27.09	8.71	59.94	0.00	0.00
EAST	5.45	25.31	2.90	28.21	9.44	57.55	10.05	57.76
TORONTO	4.59	22.18	4.23	23.12	8.37	56.72	9.81	53.08
NIAGARA	4.16	21.99	3.55	22.29	8.29	42.75	8.82	41.27
SW	4.95	21.58	3.73	23.27	5.97	47.06	9.83	46.44
BRUCE	4.45	21.59	1.31	23.39	11.22	60.99	9.52	60.15
WEST	5.39	26.96	6.05	26.05	13.48	61.37	11.85	62.14

C. Uncertainty Analysis

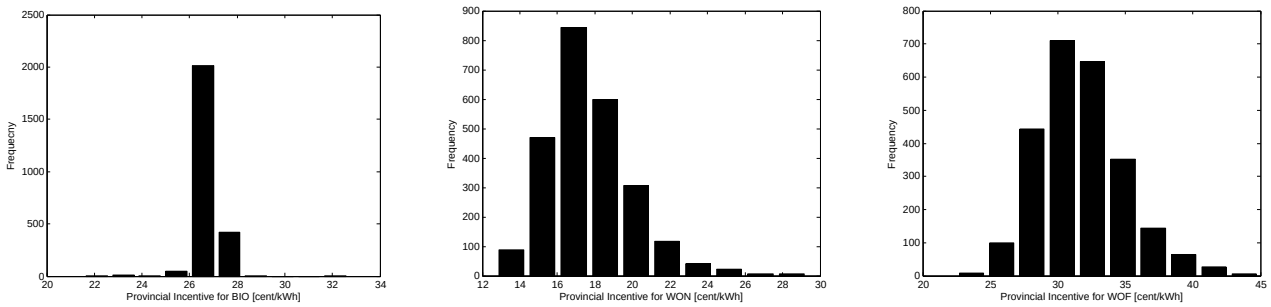
A Monte Carlo Simulation procedure was carried out and the results are presented here to examine the effect of uncertainties in solar and wind generation availabilities on plan decisions. The annual average CFs of GPV, RPV, WON, and WOF for each zone are perturbed simulatneously considering a normal 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



(a) NPV histogram of *EC*. (b) NPV histogram of *R*. (c) NPV histogram of *C*.

Fig. 12. System costs and payments from Monte Carlo simulations.



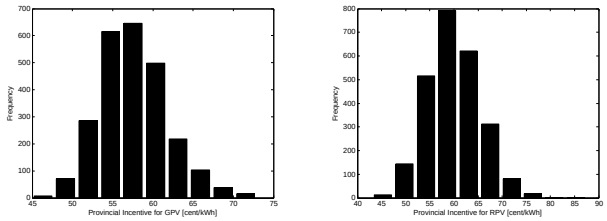
(a) Incentive histogram for BIO. (b) Incentive histogram for WON. (c) Incentive histogram for WOF.

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

TABLE X
MAIN OUTPUT VARIABLES OF MONTE CARLO SIMULATIONS

		Minimum Value	Standard Deviation	Expected (Mean)	Maximum Value	Percent Std. Dev. [%]
Total planned capacity additions [MW]	BIO	447	7.78	452.26	589	1.72
	GPV	1242	185.10	2064.62	2806	8.96
	RPV	18	35.92	216.74	261	16.57
	WON	1275	8.19×10^{-14}	1275	1275	6.42×10^{-15}
	WOF	4015	207.59	4733.54	5505	4.39
	GAS	3000	322.39	4421.15	6000	7.29
	HNR	190	1.75×10^{-13}	190	190	1.0×10^{-13}
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 Ω [Billion $]		304.66	1.69	311.02	316.52	0.543

percentage standard deviation of the probability density function of target output variables, *NC*, and ρ^{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*, and Ω) 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.



(a) GPV (b) RPV

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

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, demostrated 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 (a_0) and the optimal design of RES incentives (ρ^{New}) are mutually exclusive, thus allowing the system planner to specify the respective targets independently.

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